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SESSION 1
PAPER 1

OIL PRODUCTION BY MINING METHODS IN THE SOCIALIST REPUBLIC OF ROMANIA

G. N. Aldea
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ROMPETROL

OIL PRODUCTION BY MINING METHODS IN THE SOCIALIST REPUBLIC OF ROMANIA

Gh. Aldea and L. Sandru

Introduction

In order to ensure the amount of oil required by the economic-social development of Romania, in 1974, "The Priority Programme of the Enhancement of Oil Recovery" was worked-out. In implementing the provisions of the Programme, complex teams of specialists from Universities and Polytechnical Schools, oil equipment manufacturing plants, chemical plants, research and design institutes, oil fields etc. are participating. The Programme includes the detailed analysis, by stages, of all oil reservoirs, the setting-up, for each reservoir, of the EOR method or methods, the carrying-out of laboratory or field experiments, the industrial production of the reservoirs by the recommended methods.

In the eleven years of implementation of the above-mentioned Programme, remarkable results have been obtained, materialised by the achievement of an average country-wide recovery factor of 34 per cent, the increase in the recoverable oil reserves, the achievement, in some reservoirs, of recovery factors between 50 and 65 per cent, as well as an important contribution of the recovery methods to the annual oil production level.

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In addition to the water or gas flooding methods, to the thermal methods and to the chemical methods etc. a special attention was given to the oil production by means of mining methods as well as to the extraction of the organic mass from bituminous sands. The present paper presents the stage and the results of the application of the mining methods to the oil production in Romania.

II. Selection of the Mining Method for Oil Production and Main Provisions of the Programme Adopted

The following technical considerations underlay the application of the mining method to the oil production.

- In Romania, there is an experience in oil production by mining methods since 1925 in the Meotian reservoir of Sărata Monteoru, the oil production being carried-out by horizontal and vertical wells bored from the underground.

- The oil reservoirs, 300-500 m deep, whose production began in 1857, still contain important oil reserves.

- The possibility of drilling horizontal, inclined or vertical wells from shafts may bring out the gravity drainage.

- The field tests, applied to enhance the oil recovery factor from old reservoirs, were stopped due to the channelling of the fluids injected through old noncemented wells drilled from the surface.

- By drilling wells from the underground,

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oil recovery methods, such as steam, polymer, micellar or alkaline injection can be used and evaluated in a shorter time, having also the ability of estimating the sweep efficiency by new openings in the productive layer.

As for the main provisions of the Programme by the mining methods and the preparation of technical requirements to enhance the oil recovery factor, the following main stages and aspects are to be mentioned:

- Making the inventory of the oil reservoirs up to a depth of 500 m, reconsidering the geological and physical data of the rock and fluids, setting-up the situation of reserves (present oil saturation).

- Carrying-out supplementary research to supplement the geological-physical data.

- Carrying-out hydrogeological surveys in order to know the lithological columns and the physical-mechanical characteristics of the rock, the distribution of fluids and the gas regime, necessary to design the mining works (shafts, galleries etc.).

- Selecting the reservoirs meeting the requirements implied by the mining methods for the oil production with EOR methods utilisation.

As a result of the reservoir inventory work, and the geological and hydrogeological researches, there have been selected, in the first stage, the reservoirs: Meotian Sărata-Monteoru, Oligocene Runcu-Buştenari and Oligocene Solonţ, considered also to be representative for the other

300-500 m deep reservoirs.

III. Researches and Results

In the following section there are presented the researches carried-out in order to establish the proper equipment and technologies for the oil production by the mining methods and the utilisation of EOR methods.

III.1. The Meotian Reservoir of Sărata-Monteoru

The Meotian reservoir of Sărata-Monteoru is a monoclinal, outcropping reservoir. A series of SE-NE oriented faults separate the reservoir into several tectonic blocks. The inclination of the layers is between 34° and 36°. By the geological works carried-out from horison -25, a series of tectonic local accidents were brought out, establishing at the same time that the tectonic blocks are hydrodinamically separated.

From the stratigraphic view point, the reservoir was divided into 9 productive complexes (packages) with a total thickness of 250-300 m (Fig.1). Each complex is made up of 2-5 sandy layers, 0.1-2.5 m thick.

The present static level of the fluids was determined at the level of horison +44 and the oil/water limit is between -60 and -90 m, being different from layer to layer and from block to block.

The reservoir rocks are represented by fine to medium grained sands, generally poorly consolidated, sometimes turning to sandstones. The sands are fine to medium grained, prevailing the class 0.25–0.045 mm and the pelites.

Table 1 shows the parameters of the reservoir rock, of the fluids and the mechanical strengths of the impermeable beds in which mining works are carried-out.

In 1977, the design of the extension in depth of the old mine (horison -25) was begun with the view of opening some production patterns by mining works in order to provide good conditions for carrying-out experiments concerning the technologies for drifting the mining works, for drilling wells from the underground, the technologies for oil production as well as the preparation of technologies to enhance the oil recovery factor.

To this effect, the circulation shaft PT-50 was deepened by 78 m and 2 parallel, directional, shafts communicating in between by crosscuts were drifted at its base. The directional shafts were located in tight impermeable rocks and the cross-cuts crossed oil-saturated layers. In order to ensure the ventilation of the new mine horison, the raise S.A.I. 200 crossing saturated reservoir rocks was drilled (Fig. 2).

So far, mining works representing 1400 m were carried-out (shafts, galleries, sloping planes, raises, drilling chambers etc.). At the same time, the capacities of the air compressing stations were increased up to 90 m^3 air/min. at a pressure of 7 bar, the ventilation station capacity was raised up to 40 m^3 air/sec at a depression of 215 mm water

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column.

During the mining works at horison -25 (1979-1984) in the old mine (horison +44), the underground infill drilling of vertical wells began. Thus, in addition to the 5 wells operating since 1948, 37 more vertical wells were drilled, 60–115 m deep, the objective being complexes II and III (Fig. 3).

Since October 1984, the drilling of descending wells from the underground, 80–120 m deep, the objective being the complexes IV, V and VI as well as of horizontal wells, 80–100 m long, the objective being complex III has begun.

The drilling of descending and horizontal wells, in both horisons, was carried-out from special chambers set-up in directional shafts. The underground drilling equipment is pneumatically driven being able to drill descending wells up to 160 m deep and horizontal wells up to 250 m long.

The descending wells were equipped with a 5 in. tubing, slotted at the pay layers. The casing and slotting programme is carried-out on the basis of data obtained from well geophysical surveys.

The horizontal wells are equipped with one or two casings depending on the number of water bearing layers to be opened and a 2 3/8 in. tubing.

The distances among descending and horizontal wells are between 30 m and 35 m.

The oil production from the descending wells is by airlift, using pneumatically driven cycle programmers

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and the oil production from horizontal wells is by gravity drainage.

The fluids produced pass through two-phase separators, water and oil being transported in closed system to the underground collecting tank to which the access is forbidden and the gas is absorbed and transported to the surface.

In order to test the EOR methods at horizon -25 were drilled from the same chamber 3 groups consisting of 4 wells each in which polymers, micellar or alkaline solutions are to be injected.

In order to increase the fluid inflow in the wells drilled from the underground, the oil production under vacuum was successfully experimented and stimulation operations are under preparation.

In 1981-1984 an average amount of 40 m^3/d (252 bbl/d) oil was produced and by 1985 the oil production will reach about 74 m^3/d (465 bbl/d).

The 18 descending wells of horizon +44, producing from the pay layers of complex III, produced a cumulative of 609 m^3 (3830 bbl) in the first year and 935 m^3(5881 bbl) after the second operational year (Fig.4). Extrapolating the results for a period of 10 years, the theoretically calculated average cumulative oil production will be 1577 m^3 per well (9919 bbl/well).

Out of the 18 wells analysed, three wells had a good behaviour, their cumulative production estimated for a 10 year operational time being achieved in about 2.5

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years (Fig.5). As compared to the operation of the descending wells producing from complex III, may be mentioned the drainage capacity of the ventilation shaft S.A.I. 200 (the sinking profile 4.8 m^2 supported in wood) whose cumulative production was more than 4343 m^3 (27,316 bbl) of oil (Fig. 6) after 4 years of operation.

The descending wells drilled for the production of oil from complexes V and VI had initial rates of 4 - 4.5 m^3/d (25-28 bbl/d), the production being stabilized after 1-2 weeks at 2.9-3.4 m^3/d (18-21 bbl/d). The water cut varies between 10 and 40 per cent (Fig. 7).

As for the horizontal wells drilled at the level of horizon -25 to open and produce the oil layers in complex III, they have an average inflow of 10 m^3/d (63 bbl per day) with 65-69 per cent water cut.

Taking into account the results obtained, by 1987, the construction of a new mine (Fig.2) planned to recover 857,000 m^3 (5,390,000 bbl) of oil in 30 years with an average production of 29-30,000 m^3/year (182-188,000 bbl per year) providing an average recovery factor of 50 per cent will begun. Moreover by 1988-89, the results will be extended to other Meotian reservoirs. The drilling for supplementary geological surveys of these reservoirs [illegible] began this year.

III.2. The Oligocene Reservoir of Runcu-Buştenari

In the Runcu-Buştenari area, the oil accumulations are in Oligocene, Helvetian and Meotian formations.

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The oil production began in 1857 by manually bored shafts and wells. All in all, about 2295 wells have been drilled.

The main reservoir is the Oligocene, of monocline type, having slopes of 70-75° (Fig.6). The reservoir has a complicated tectonics with longitudinal and transversal faults, which divide it into a series of separate tectonic blocks.

The reservoir rocks saturated with hydrocarbons are made up of sands and siliceous brittle gray-yellowish, fine to medium grained sandstones.

Detailed geological researches and hydrogeological works were carried-out for a better knowledge of the reservoir from the geological and mining viewpoint and choosing the location of the pilot mine for the oil production. In total, there have been drilled 52 wells 400-600 m deep. In general, one well for about 4 ha. of surveyed area. Table 1 shows the main parameters of the rocks and fluids as well as the strengths of the impermeable rocks in which the mining works are carried-out.

In order to appraise the possibilities and the conditions for the application of the mining methods to oil production and enhancement of the oil recovery from the Oligocene reservoir of Runcu-Bustenari, a field test was designed to be carried-out within a pilot mine located in representative conditions of reservoir.

The design of the pilot mine includes:

- opening of the reservoir by two shafts, 330 m deep each, located at a distance of 68 m from each

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other. The shafts are located at the bottom of the pay formation, in impermeable rocks belonging to the Middle Oligocene of Podul Morii. Along the first 250 m they will cross Meotian formations;

- creation of a mining horizon, at the bottom of the shafts, which will be, in the first stage, in the impermeable rocks of Podul Morii and later on in the reservoir (about 2,000 m galleries). The mining horizon was located at 30-40 m above the initial oil/water level;

- drilling of drainage horizontal and ascending wells, 100-150 m long, from chambers created on purpose (Fig. 9).

The pilot mine area has 23.2 ha, the recovery factor by primary methods being 35 per cent.

It was estimated that by the mining method about 503-514,000 m^3 (3164-3233,000 bbl) of oil will be recovered in 15 years and the recovery factor will increase to about 60 per cent having in view the high slope of the layers.

The preparation of the experiment has begun in 1982. In 1984 [illegible] began the boring of the mine shafts with a diameter of 2.96 m. The shafts are bored with the drilling rig P-320 M.

The consolidation of the shafts is carried-out by metallic string, cemented at the back side as the drilling advances.

So far, the precursory shafts with useful diameter of 4.0 m and 32.0 m deep each were bored by means of classical mining methods. The first shaft will be ready in

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August-September 1985.

By the end of 1985, the mining works will begin at the bottom of the shaft.

The underground shafts will be drilled by blasting and will be supported by prefabs in reinforced concrete, erected in a mechanised way.

In case of good results, one envisages, for the next stage, to extend the activity of the pilot mine of Runcu-Buştenari, to the adjacent areas, for the supplementary recovery of 1.4-1.5 (8.8-9.4) million m^3 (bbl) of oil.

III.3. The Oligocene Reservoir of Solonţ

The production of oil accumulations at Solonţ began in 1886. The Oligocene is under the form of outcropping anticline. The bed slope is about 18-30°. The reservoir is divided into tectonic blocks by a system of almost vertical faults (Fig. 10).

The reservoir rocks saturated with oil, 20-25 m thick, are made up of siliceous white-yellowish, generally fine-grained, poorly cemented sandstones.

Table 1 shows the average values of the rock and fluid physical parameters as well as the strengths of the impermeable formation.

In order to experiment and finalise the mining work technologies, 2 experiments were designed having the following goals (Fig. 11) :

- Experimental Sector Solonţ I to test and develop the shaft boring technologies by means of the explo-

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sives having in view the hardness of the rocks in which the oil mines will be built, as well as for the finalization of the boring technology, construction of wells and necessary tools and equipment. The research has began in 1984 by testing and finalising the blasting technologies and those of the mining works in hard and very hard rocks, in an adit, 200 m long. Because in boring the experimental adit some oil collectors were opened, the activity is extended for the preparation of some mining patterns to get a supplementary oil production.

- Experimental sector Solonţ II, for the implementation of oil production technology in the Oligocene reservoirs in Moldavia. It is envisaged to bore 2 mining shafts with a diameter of 4 m and 310 m deep, using the rig type F-400-M, to bore 2,200 m shafts and 8-10,000 m underground drilling. It was estimated that the present recovery factor will increase by 21 per cent, recovering 68,600 m^3 (431,000 bbl) of oil.

IV. Work Safety Measures in Oil Mines

In oil production by mining methods, supplementary measures for fire and underground explosion prevention and fighting were taken due to the presence in the underground atmosphere of higher methane homologues, of the vapour of liquid hydrocarbons and oil having low flame temperature and high speed of fire spreading.

In order to prevent such accidents during the experiments in pilot mines and for the endowment of the future oil mines, spark killer equipment and installations

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have been developed, necessary for mining works, drilling of wells from the underground, oil and gas production, separation and transport as well as for all fire-fighting and control means.

A special attention was given to the development of measures to prevent industrial diseases. It was considered necessary to achieve a permanent and automated control of the underground atmosphere by means of explosimetric devices and a good ventilation to hinder gas segregation (0.5 m/sec minimal air speed in shaft boring and 2.0 m/sec minimal air speed in well drilling and oil production).

V. Estimation of the Cost of Oil Produced by Mining Methods

As presented above, in the oil mine of the Sărata Monteoru Meotian, both mining works (galleries, shafts, raises etc) and underground drilling and oil production works were carried-out. The value of those works, plus the expenditures related to oil production by mining methods, its treatment and transport show that the cost price for the ton of oil is under the price of the ton of oil obtained in Romania by tertiary methods (polymer, micellar or alkaline solutions injection).

VI. Conclusions

1. In Romania, oil production by mining methods was highly extended within the "Priority Programme on

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the Enhancement of Oil Recovery".

2. In order to establish the technical conditions for the oil production by mining methods and to enhance the recovery factor there have been carried-out:

- inventory of all 300-500 m deep reservoirs;
- supplementary geological and hydrogeological researches necessary for designing mining works;
- selection of reservoirs suitable for oil production by mining methods as well as the technologies for enhancing the recovery factor.

3. The Meotian reservoir of Sărata Monteoru by the mining and drilling works and oil production has constituted the pilot mine in which there have been developed descending and horizontal drilling technologies, necessary tools and equipment, ventilation, work safety measures etc. Works on production stimulation operations and implementation of EOR methods are under way.

4. In addition to the oil mine of Sărata Monteoru, works at the Oligocene reservoir of Solonţ and Oligocene reservoir of Runcu-Buştenari are designed and carried-out.

5. From the economic point of view, the price of the ton of oil produced by mining works is lower than the price of the ton of oil produced by tertiary methods.

TABLE 1

PHYSICAL PROPERTIES OF ROCK MATERIAL AND FLUIDS AND MECHANICAL PROPERTIES OF BARREN ROCKS

FIELD	POROSITY, ϕ, %	PERMEABILITY, k, $10^{-3}\mu m^2$ (mD)	OIL SATURATION, S_t, %	OIL DENSITY, ρ, kg/m³	OIL VISCOSITY AT 20°C, μ, mPa·sec(cP)	STRENGTH	
						COMPRESSION, σ_c, MPa	TENSION, σ_t, MPa
MEOTIAN SĂRATA MONTEORU	30	1000	16~80	862~896	9.7~518	2.6~8.0	0.6~1.9
OLIGOCENE RUNCU – BUȘTENARI	25	300	30	840	5.6	14.2~30.0	1.2~3.5
OLIGOCENE SOLONȚ	12	15	24	840	3.5~11.4	10.0~100.0	0.5~12.5

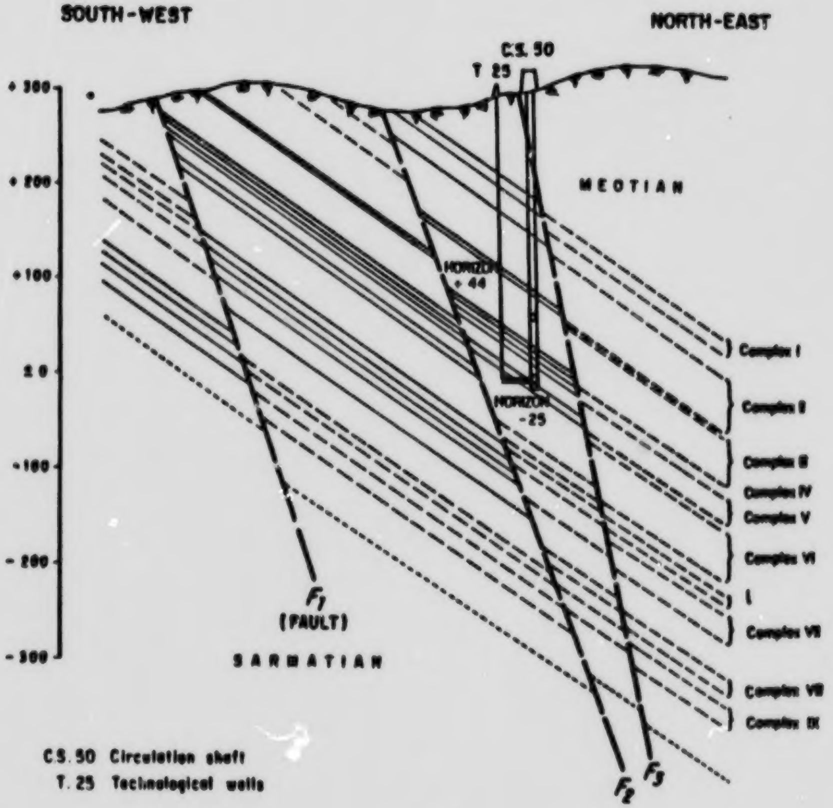


FIG. 1 GEOLOGICAL SECTION, MEOTIAN RESERVOIR OF SĂRATA - MONTEORU

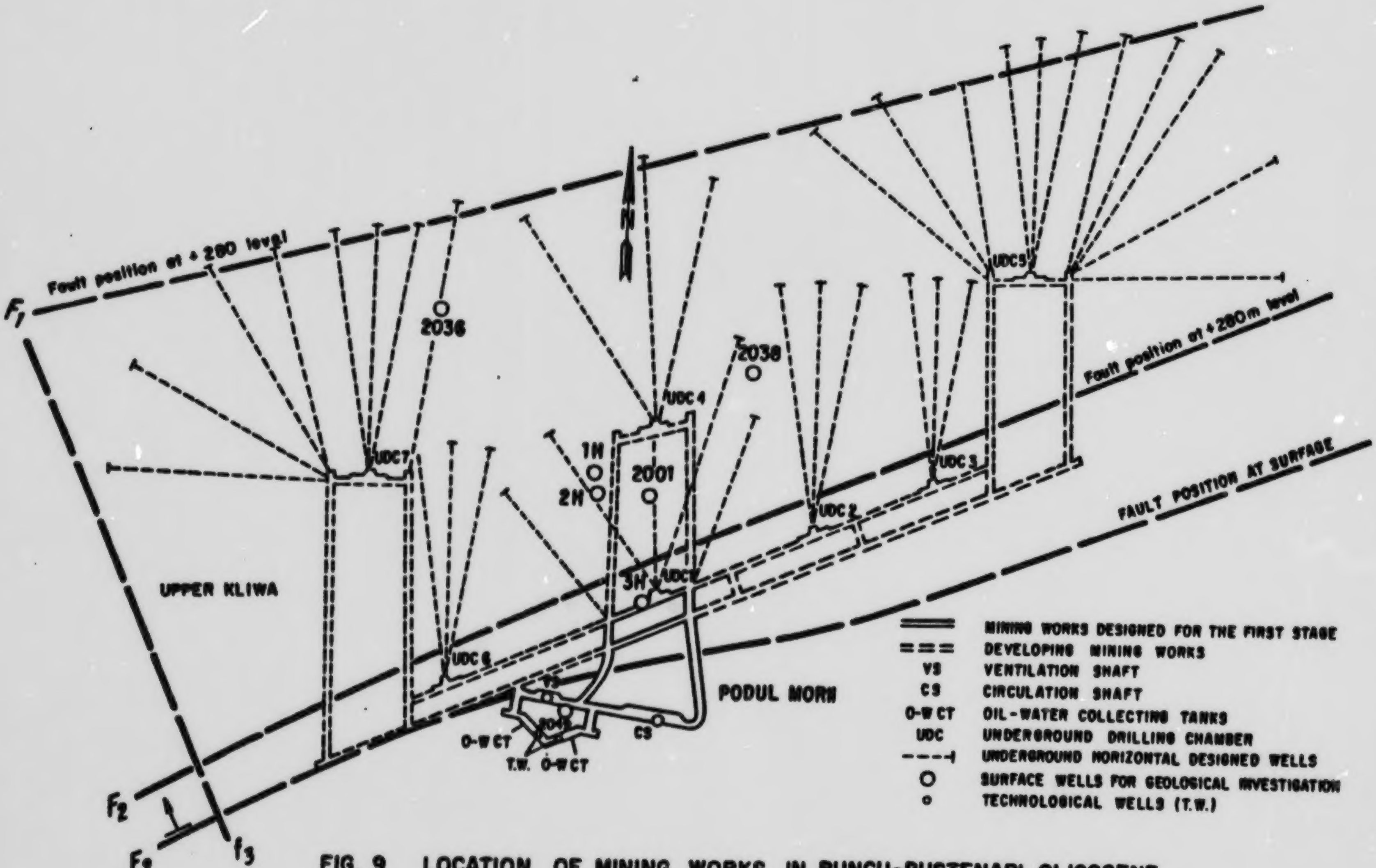

Fault position at +280 level
F1
2036
N
UDC 7
UDC 6
UDC 4
1H
2H
2001
3H
UDC
2038
UDC 2
UDC 3
UDC5
Fault position at +280m level
FAULT POSITION AT SURFACE
UPPER KLIWA
PODUL MORII
VS
CS
O-W CT
T.W.
F2
F2
f3
MINING WORKS DESIGNED FOR THE FIRST STAGE
DEVELOPING MINING WORKS
VS VENTILATION SHAFT
CS CIRCULATION SHAFT
O-W CT OIL-WATER COLLECTING TANKS
UDC UNDERGROUND DRILLING CHAMBER
UNDERGROUND HORIZONTAL DESIGNED WELLS
SURFACE WELLS FOR GEOLOGICAL INVESTIGATION
TECHNOLOGICAL WELLS (T.W.)

FIG. 9 LOCATION OF MINING WORKS IN RUNCU-BUȘTENARI OLIGOCENE

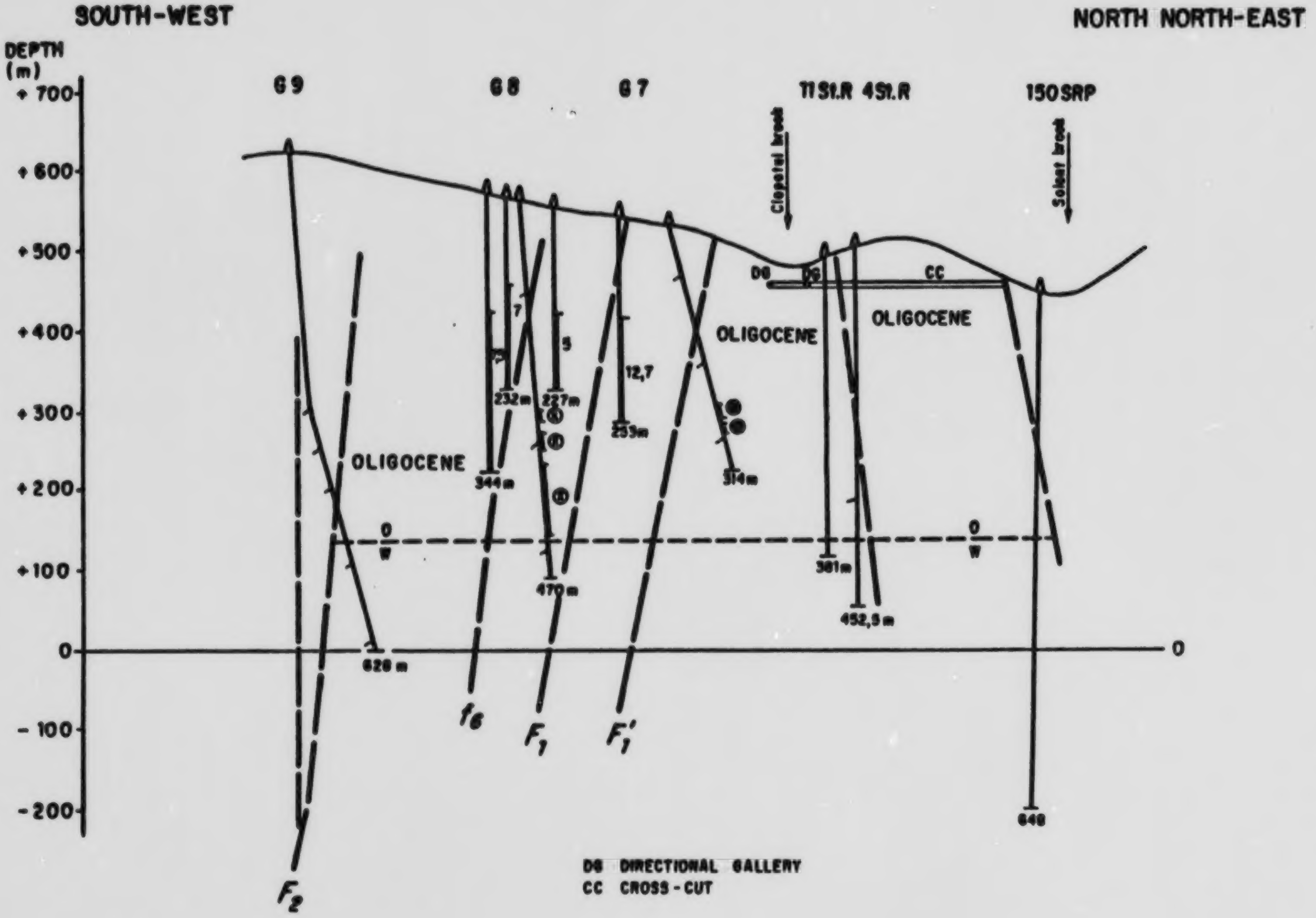


FIG. 10 GEOLOGICAL SECTION, OLIGOCENE RESERVOIR OF SOLONT

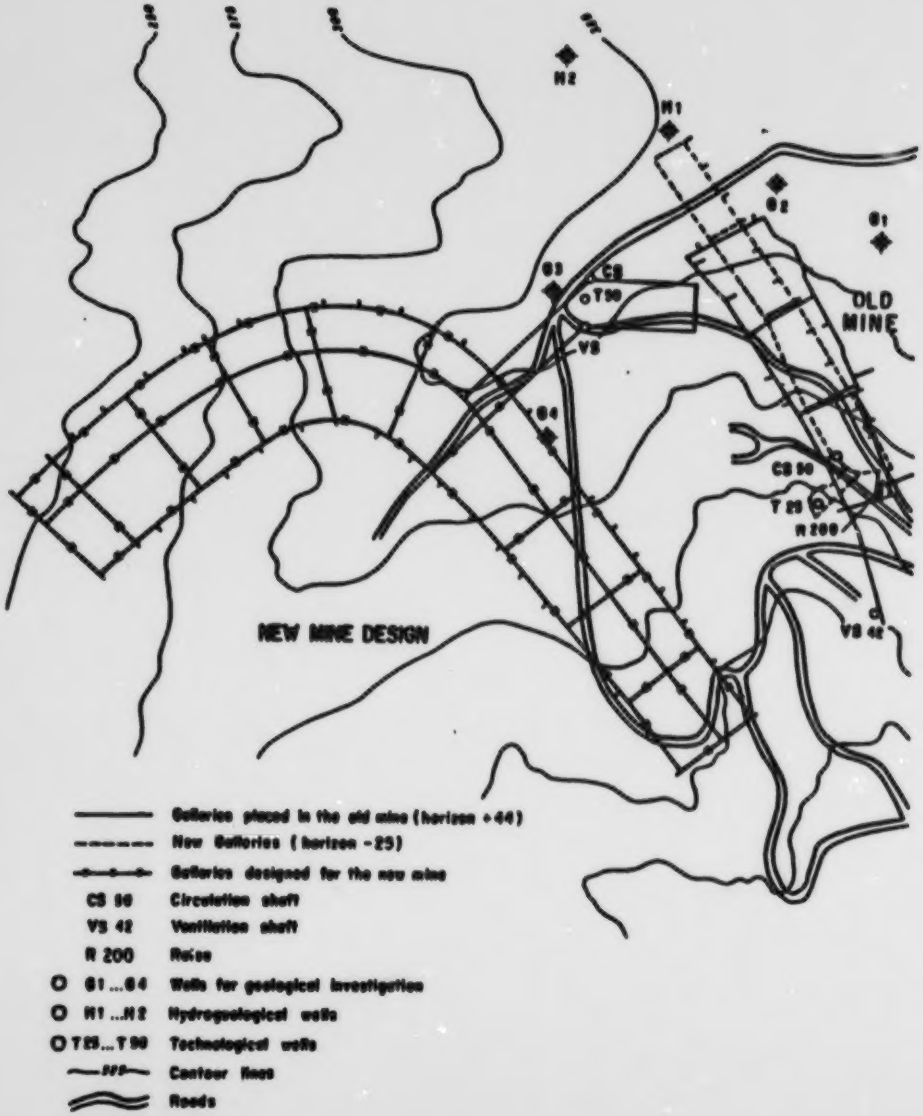

H2
H1
G2
G1
G3
CS
T90
VS
G4
OLD MINE
CS 90
T 25
R 200
VS 42
NEW MINE DESIGN
Galleries placed in the old mine (horizon +44)
New Galleries (horizon -25)
Galleries designed for the new mine
CS 90 Circulation shaft
VS 42 Ventilation shaft
R 200 Raise
G1 ... G4 Wells for geological investigation
H1 ... H2 Hydrogeological wells
T25 ... T90 Technological wells
Contour lines
Roads

FIG. 2 LOCATION OF MINING WORKS IN SÅRATA-MONTEORU MEOTIAN

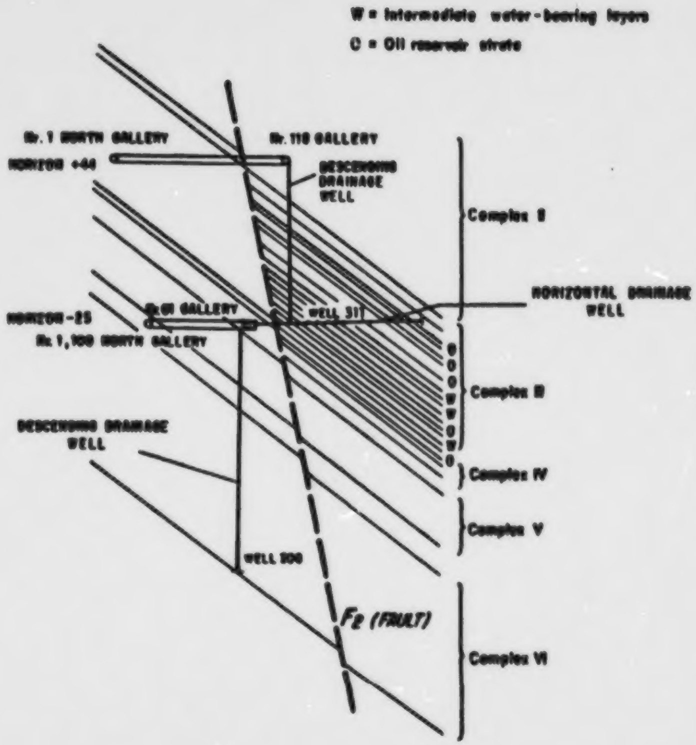


FIG. 3 DESCENDING AND HORIZONTAL WELLS DRILLED FROM THE GALLERIES PLACED IN THE MEOTIAN HORIZONS +44 AND -25 OF SÅRATA-MONTEORU

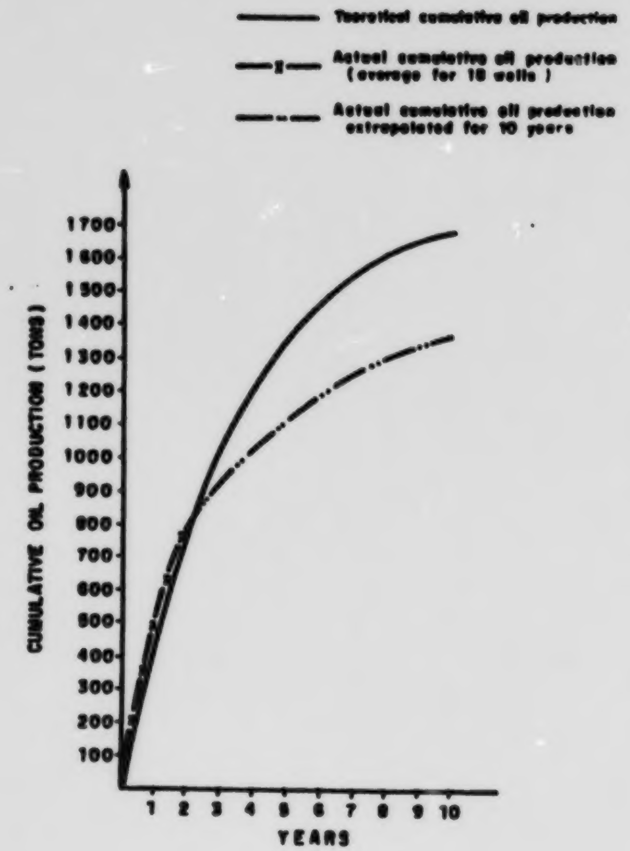


FIG. 4 EVOLUTION OF OIL PRODUCTION IN MEOTIAN, COMPLEX III, OF SÅRATA - MONTEORU (HORIZON +44)

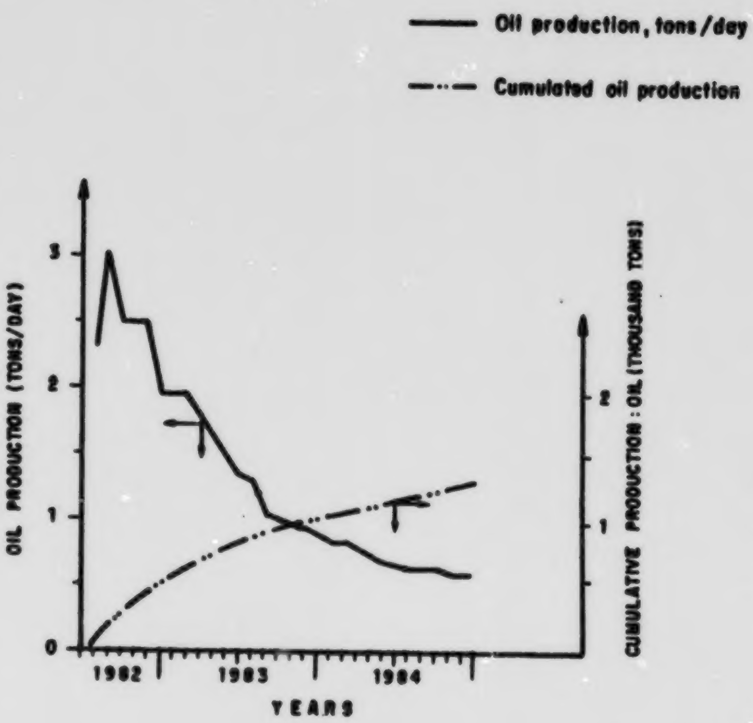


FIG. 5 OIL PRODUCTION FROM THREE WELLS DRILLED IN COMPLEXES Nr. I AND III OF SÅRATA - MONTEORU

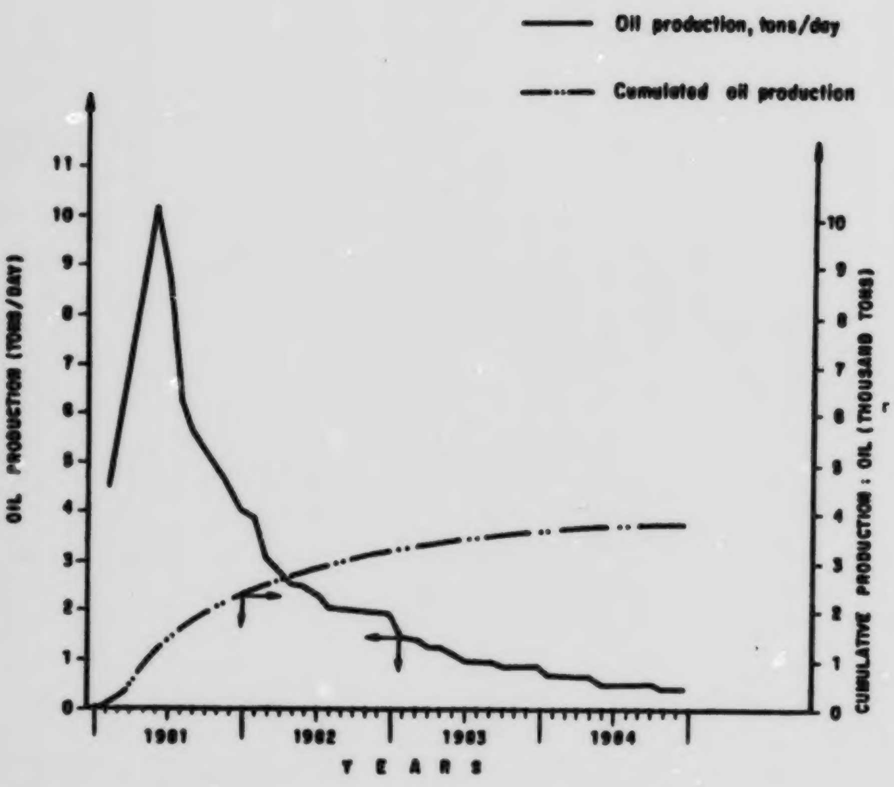


FIG. 6 OIL PRODUCTION FROM RAISE 200

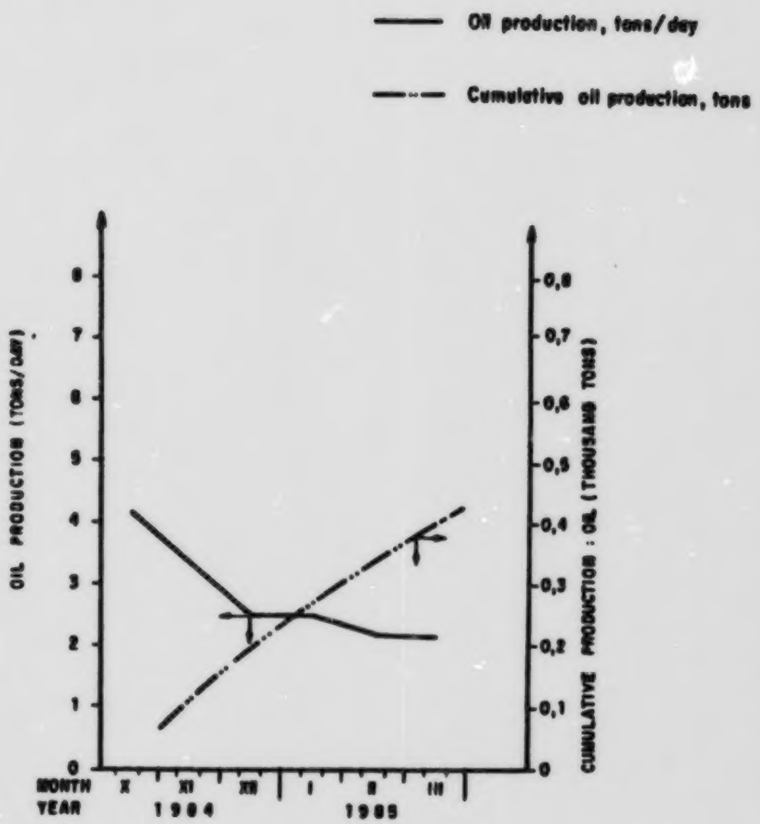


FIG. 7 OIL PRODUCTION FROM TWO WELLS DRILLED IN MEOTIAN COMPLEXES Nr. V AND VI OF SÁRATA - MONTEORU

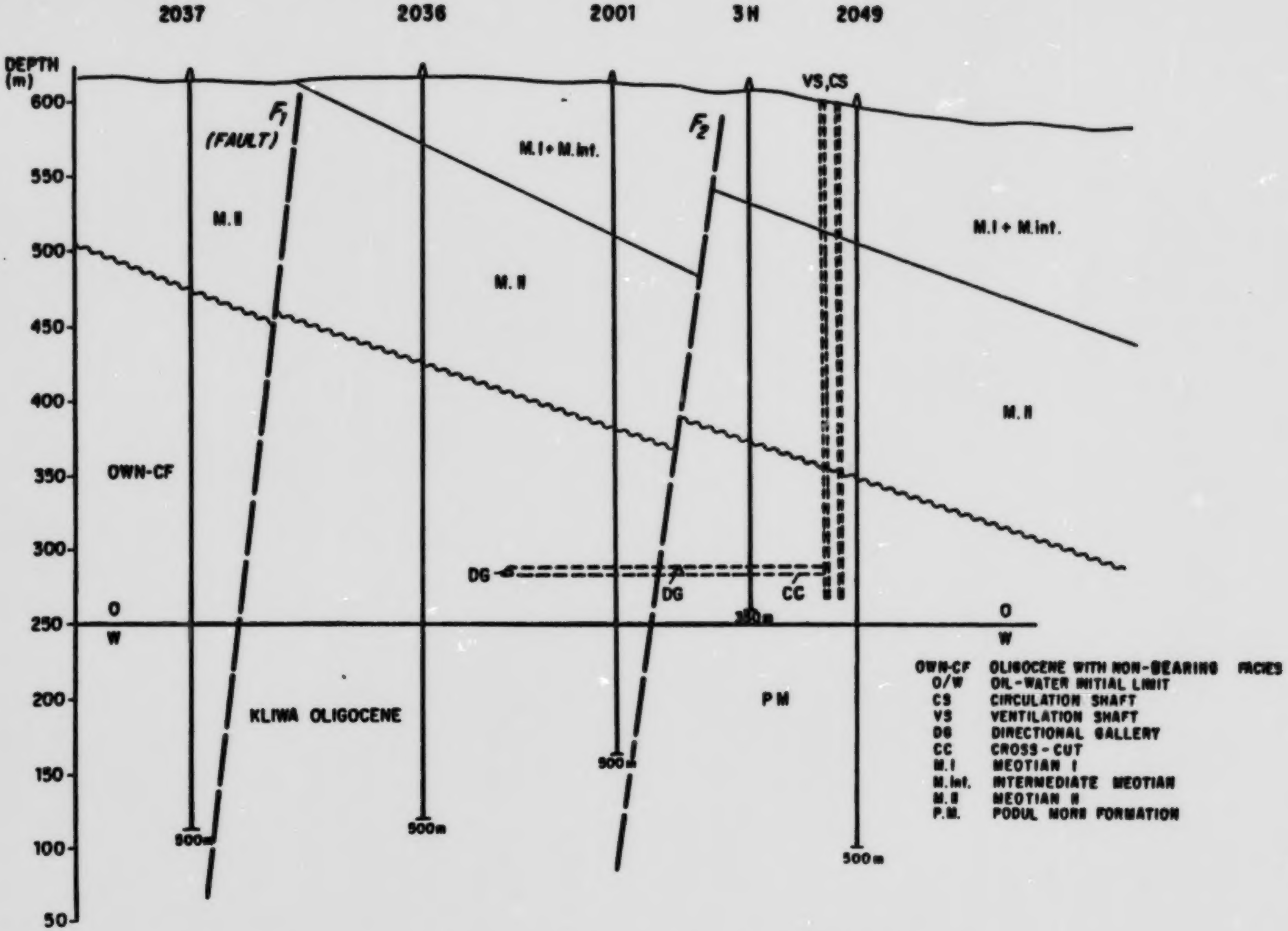
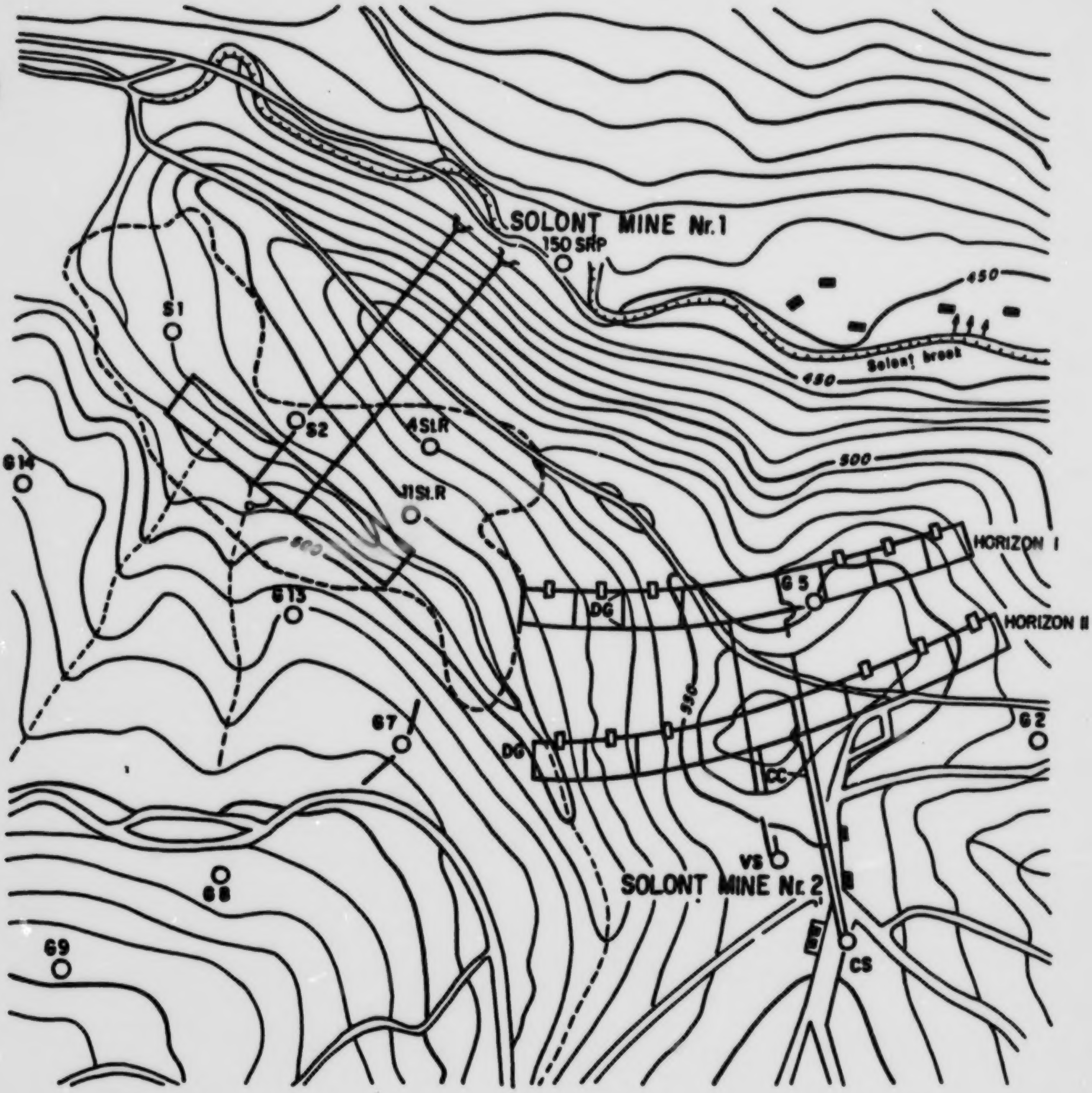


FIG. 8 GEOLOGICAL SECTION, RUNCU - BUȘTENARI OLIGOCENE



○	Old oil wells
○G1	Wells for geological investigation
○CS	Circulation shaft
○VS	Ventilation shaft
DG	Directional gallery
CC	Cross-cut

FIG. 11 LOCATION OF MINING WORKS IN SOLONȚ OLIGOCENE

L'INTÉRÊT DU FORAGE HORIZONTAL POUR L'EXPLOITATION DE GISEMENTS D'HYDROCARBURES

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[Advantages of Horizontal Drilling for Production from Hydrocarbon Fields]

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Pour les gisements de faible épaisseur, la longueur productive d'un puits horizontal est considérablement plus forte que celle d'un puits vertical. La productivité du puits horizontal croît avec la longueur de celui-ci, quoique plus lentement qu'elle, puisque intervient une loi pression-distance en logarithme. Les calculs analytiques et les simulations sur modèles numériques montrent que le gain de productivité peut atteindre couramment un facteur de 3 à 5. Dans des gisements comprenant des fractures verticales parallèles, un puits horizontal disposé perpendiculairement à elles est susceptible d'en recouper un très grand nombre et d'apporter les gains de productivité beaucoup plus importants. Dans le cas des gisements très hétérogènes en perméabilité, tels que les gisements karstiques, le puits horizontal a de grandes chances de rencontrer des zones très productives (cas de Rospo Mare à gain de productivité de 10 et plus constaté par rapport aux puits verticaux voisins). Une étude menée sur la productivité globale à l'échelle du champ confirme que pour obtenir une même production dans des conditions équivalentes, le remplacement de puits verticaux par des puits horizontaux peut permettre d'en diviser le nombre par un facteur de l'ordre de 4.

Pour la lutte contre les venues d'eau (ou de gaz) en écoulement polyphasique, le puits horizontal présente deux avantages. Il est possible de le placer en haut du gisement de façon à obtenir la garde à l'eau la plus importante. De plus, même avec une production totale supérieure, la production linéique, ou production par unité de longueur, est plus faible, entraînant localement une sollicitation plus modérée de la surface de séparation huile/eau ou huile/gaz. La forme de cette dernière est donc plus molle et les calculs montrent que le balayage vertical est plus efficace, donc la récupération plus élevée.

D'une façon générale, en écoulement polyphasique, les puits horizontaux manifestent une supériorité d'autant plus nette que le rapport de mobilité est défavorable, huile lourde balayée par de l'eau par exemple. Le phénomène nocif est en effet la percée des fronts, qui est d'autant plus précoce que l'écoulement est instable. La régularité du drainage entre puits horizontaux apporte une progression plus homogène des fronts, particulièrement avantageuse en début de production. Cependant, les gisements comportant toujours des hétérogénéités, on ne pourra bénéficier complètement de ces effets favorables que si l'on parvient

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à maîtriser les complétions sélectives en puits horizontal. Pour des raisons en partie semblables, les puits horizontaux possèdent des atouts pour la récupération thermique. Le positionnement précis d'une rampe d'injection à une profondeur définie dans le gisement devrait permettre d'y faire pénétrer facilement de la vapeur de façon à ce que la zone qu'elle envahit se développe régulièrement, tout en diminuant les pertes thermiques dans les épontes.

Enfin, il faut ajouter que les puits horizontaux se sont révélés, grâce aux surprenantes performances des diagraphies et du carottage, de très riches outils de connaissance de l'évolution latérale des faciès et de la répartition des fluides dans le gisement.

For fields with little vertical thickness, the productive length of a horizontal well is considerably greater than that of a vertical well. The productivity of a horizontal well increases with its length, although more slowly than this length because a logarithmic pressure-distance law comes into play. Analytical derivations as well as simulations on numerical models show that the increase in productivity may regularly attain a factor of 3 to 5. In fields having parallel vertical fractures, a horizontal well drilled perpendicularly to these fractures should cut across a great many of them and thus provide a much greater increase in productivity. In the case of fields with very heterogeneous permeability, such as karstic reservoirs, a horizontal well has a very good chance of encountering highly productive zones (case of Rospo Mare in Italy where a productivity increase of 10 and more was found in comparison with neighboring vertical wells). A study of overall productivity on the scale of the field confirms that, if vertical wells are to be replaced by horizontal wells, their number may be divided by a factor of about 4 to obtain the same production under equivalent conditions.

To prevent water (or gas) influxes during multiphase flow, a horizontal well has two advantages. It can be drilled near the top of the reservoir so as to obtain as much clearance as possible. Likewise, even with greater total production, production per unit length is less, thus locally causing more moderate stress on the oil/water or oil/gas interface. The shape of this interface is thus smoother, and calculations show that vertical sweep is more efficient, and hence recovery is greater.

Generally speaking, in multiphase flow, horizontal wells reveal all the more superiority as the mobility ratio is unfavorable, e.g. heavy oil driven by water. The phenomenon to be prevented is indeed the breakthrough of fronts, which occurs all the sooner as flow is more unstable. The steadiness of drainage among horizontal wells provides more homogeneous progression to fronts, which is especially advantageous at the beginning of production. Nonetheless, since reservoirs are more or less heterogeneous, full benefit can be drawn from such favorable effects only if selective completions can be implemented in horizontal wells.

For partly similar reasons, horizontal wells are advantageous for thermal recovery. The exact positioning of a perforated injection casing at a specific depth in a reservoir should enable steam to be fed in easily so that the zone it invades expands steadily, while decreasing heat losses into the surrounding formations.

Lastly, it should be added that horizontal wells, thanks to surprisingly good logging and coring performances, have proven to be extremely valuable instruments for determining the lateral evolution of facies and of fluid distribution in the reservoir.

Para los yacimientos de poco espesor, la longitud productiva de un pozo horizontal es mucho mas importante que la de uno vertical. La productividad de un pozo horizontal aumenta con la longitud de este, aunque mas lentamente, ya que interviene una ley presión-distancia logarítmica. Los calculos analíticos y las simulaciones con modelos numéricos indican que el aumento de productividad puede alcanzar, corrientemente, un factor de 3 a 5. En los yacimientos con fracturas verticales paralelas, un pozo horizontal dispueto perpendicularmente a ellas es susceptible de atravesarlas en gran número pudiendose así obtener aumentos de productividad mucho mas importantes. En el caso de yacimientos muy heterogéneos en la permeabilidad, como los kársticos, el pozo horizontal tiene grandes probabilidades de encontrar zonas muy productivas (caso de Rospo Mare, aumento de productividad de 10 y mas frente a la de los pozos verticales vecinos). Un estudio efectuado sobre la productividad global a la escala del yacimiento confirma que para obtener una igual producción en condiciones equivalentes, la substitución de pozos verticales por los horizontales puede permitir de dividir su número por un factor del orden de 4.

En la lucha contra las llegadas de agua (o de gas) en derrame polifásico, el pozo horizontal presenta dos ventajas. Es posible situarlo en lo alto del yacimiento de manera que se obtenga una guarda, lo mayor posible, contra el agua ; además, aún con una producción total superior, la producción lineal (por unidad de longitud), es menor, causando localmente una solicitación mas moderada de la superficie de separación crudo/agua o crudo/gas. Así pues, la forma de esta ultima es mas elastica y los calculos indican que el barrido vertical es mas eficaz y por consiguiente la recuperación mas importante.

De manera general, en derrame polifásico, los pozos horizontales presentan una superiodidad tanto mas evidente que el factor de mobilidad es desfavorable, aceite pesado desplazado por el agua por ejemplo. En efecto, el fenómeno nocivo es la rotura de los frentes, que es tanto mas precoz que el derrame es inestable. La regularidad del drenaje entre pozos horizontales contribuye a una progresión mas homogénea de los frentes, lo que es particularmente ventajosos en los comienzos de la producción. Sin embargo, como que en los yacimientos existen siempre heterogeneidades, no se podrá beneficiar completamente de estos efectos favorables que si se consigue dominar las terminaciones selectivas en pozo horizontal.

Por razones en parte semejantes, los pozos horizontales presentan ventajas para la recuperación térmica. La implantación precisa de una rampa de inyección a una profundidad definida en el yacimiento tendria que permitir una facil penetración del vapor de manera que la zona por él invadida se extienda de manera regular, disminuyendo al mismo tiempo las perdidas térmicas en los hastiales. Para terminar hay que añadir que los pozos horizontales han demostrado, gracias a las sorprendentes performances de las diagrafías y de la toma de testigos, que son herramientas muy interesantes para conocer la evolución lateral de las faciés y de la distribución de los fluidos en el yacimiento.

NOTATIONS

En général, les notations reprises sont celles de l'*American Institute of Mining, Metallurgical and Petroleum Engineers (AIME)* éventuellement adaptées en Français pour ce qui concerne les indices.

a : distance entre les centres de deux puits horizontaux consécutifs ;
D : demi-distance entre deux fractures ou deux failles ;
D' : demi-longueur du compartiment de gisement pris en considération ;
E_d : efficacité de déplacement ;
E_v : rapport du volume balayé par l'eau au volume d'huile ;
g : gravité ;
h : hauteur de la couche du gisement imprégnée d'huile ;
h_f : hauteur de la fracture ;
h_p : hauteur perforée d'un puits producteur ;
h_{pD} : hauteur perforée adimensionnelle ;
IP_V : indice de productivité d'un puits vertical ;
IP_{VF} : indice de productivité d'un puits vertical fracturé ;
IP_H : indice de productivité d'un puits horizontal ;
IP_{HF} : indice de productivité d'un puits horizontal fracturé ;
k : perméabilité moyenne ;
k' : moyenne géométrique des perméabilités verticale et horizontale ;
k_h : perméabilité horizontale ;
k_{re} : perméabilité relative à l'eau ;
k_{rh} : perméabilité relative à l'huile ;
k_v : perméabilité verticale ;
k_x : perméabilité horizontale selon l'axe des x ;
k_y : perméabilité horizontale selon l'axe des y ;
ℓ : longueur productive du puits horizontal ;
L : distance d'un puits horizontal à la limite latérale du gisement ;
Log : désigne la fonction logarithme népérien ;
M : rapport de mobilité ;
n : nombre de branches d'un système de puits horizontaux ramifiés en étoile ou nombre de puits verticaux fracturés ;
N_{pD} : production cumulée adimensionnelle ;
Q : débit de production hydratée ;
Q_{cr} : débit critique du puits horizontal ;
Q_h : débit de production anhydre ;
$q_{cr\infty}$: débit linéique critique du puits horizontal infini ;
r : rayon d'un puits ;
r' : rayon d'un puits qui serait équivalent à un puits dévié ou fracturé ;
r_D : rayon du puits adimensionnel ;
r_e : rayon extérieur de la zone drainée par le puits ou rayon de drainage ;
r_{eD} : rayon de drainage adimensionnel ;
R_e : nombre de Reynolds ;
S_{ei} : saturation initiale en eau ;
S_{hr} : saturation irréductible en huile ;
T : temps de production ;
X_f : demi-extension latérale d'une fracture ;
α : inclinaison d'un puits dévié ;
β : facteur multiplicatif ;
δ : distance verticale entre le milieu de la couche et le centre de la fracture ;
θ : pendage du banc réservoir mince ;
$\Delta\rho$: différence de densité entre deux fluides ;
μ : viscosité ;
μ_e : viscosité de l'eau ;
μ_h : viscosité de l'huile ;
ϕ : porosité du réservoir.

Avertissement : Les volumes et débits sont calculés en condition de fond.

1. INTRODUCTION

La découverte du champ de Rospo Mare, en Adriatique italienne, a suscité le recours au concept de forage horizontal au sein du groupe *Elf-Aquitaine*. Il s'agissait d'exploiter en Europe un important gisement d'huile très visqueuse, limité inférieurement par un aquifère susceptible d'ennoyer rapidement les puits verticaux envisagés à travers les fissures. De là naquit l'idée de forer des drains horizontaux proches du toit du réservoir. Leur extension latérale leur permettrait, en recoupant de nombreuses fissures, d'atteindre une productivité globale importante, et ce au prix d'un soutirage linéique moyen qui ne nécessite qu'une sollicitation locale de l'aquifère modérée.

Ce concept avait déjà inspiré à l'industrie pétrolière diverses tentatives depuis presque un demi-siècle : réalisation de puits rayonnants forés à partir d'un puits de mine dans les années 1940 aux Etats-Unis [1] et de puits ramifiés forés en Union Soviétique dans les années 1950 sur des champs anciens afin d'en augmenter la productivité [2 et 3].

Plus récemment, l'utilité des puits horizontaux a été mise en évidence aux Etats-Unis et au Canada [4, 5, 6 et 7]. Il s'agissait soit d'éviter les venues de gaz (*gas coning*), soit d'atteindre un objectif lointain, soit encore et surtout (projet *Cold Lake* au Canada) d'installer à la base d'un réservoir d'huile très épaisse des rampes de chauffage pour injection de vapeur.

La volonté de mettre en production le champ de Rospo Mare et, d'une manière plus générale, le désir d'améliorer la productivité des puits et le balayage des réservoirs, ont abouti à l'établissement d'un projet de recherche scientifique et technique. Ce projet est mené par l'association entre un organisme de recherche scientifique, l'*Institut Français du Pétrole*, et un opérateur industriel, la *Société Nationale Elf-Aquitaine*. Avec un soutien de la *Communauté Economique Européenne* (*CEE*) et une enveloppe financière d'une cinquantaine de millions de francs répartie sur cinq ans, cet effort a déjà abouti au forage de trois puits horizontaux, dont deux en France sur le champ de Lacq Supérieur et un en mer, ce qui constitue une première mondiale, à Rospo Mare au large de l'Italie [7 bis].

Les études en gisement entreprises au début du projet, simultanément avec la détermination des butoirs technologiques éventuels, ont eu pour objet l'inventaire des cas où le forage horizontal serait à préconiser.

Si le forage horizontal ne semble pas devoir fournir un procédé universel, trois thèmes particuliers sont propices à sa mise en oeuvre. Il s'agit de la production des gisements où les facteurs susceptibles de limiter la productivité sur un champ sont la faible épaisseur, la mauvaise perméabilité, la viscosité importante de l'huile ou une combinaison des trois ; huile lourde ou réservoir compact à gaz (*tight gas*) par exemple. Il s'agit également de l'amélioration des mécanismes de production multiphasique : venues d'eau ou de gaz, balayage et récupération thermique. Le forage horizontal est également un concurrent potentiel de la fracturation hydraulique, notamment dans la craie, dont la malléabilité interdit aux agents de soutènement de maintenir la fracture ouverte.

Dans les réservoirs peu épais, peu perméables ou peu fissurés, la longueur du drain permet d'améliorer le produit lk – analogue au produit hk des puits verticaux – et elle permet également d'augmenter la probabilité de recouper des fissures qui sont le plus souvent verticales. Les meilleurs candidats pour les puits horizontaux sont les gisements dont le réseau matriciel est peu perméable et où les fissures ou accidents ne sont pas très fréquents. Si l'on recherche également à améliorer l'efficacité du balayage de l'huile par un fluide vecteur, eau, gaz, vapeur, dioxyde de carbone, les candidats les plus adaptés au forage horizontal seront les gisements relativement minces, à huile épaisse ou avec un problème d'effet de cône au gaz. Celui-ci est également prometteur pour la mise en mouvement d'huile de bordure ou piégée dans les coins.

Citons ici un sujet qui intéresse l'ingénieur en gisement pour les informations nouvelles qu'il peut en tirer, à savoir les diagraphies dans les puits horizontaux(3).

Dans ce qui suit, nous envisageons successivement, pour diverses configurations de puits horizontaux et verticaux, leurs productivités comparées dans des bancs homogènes de diverses épaisseurs.

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(3) En forage horizontal comme en forage vertical, plus on obtient d'informations spécifiques, meilleure est la connaissance du gisement. C'est pour cette raison que des techniques particulières de mise en place et de déplacement des sondes de mesure ont été développées pour les puits horizontaux. Il s'agit, d'une part, du pompage dans le train de tiges de sondes de diamètre réduit qui émergent au droit du découvert (procédé Schlumberger) et, d'autre part, d'un procédé original développé au sein de notre projet de recherche, le Système d'Instrumentation et de Mesure pour les Puits HORizontaux (SIMPHOR, marque déposée) qui permet de réaliser des diagraphies avec des sondes de diamètre standard fixées à l'extrémité du train de tiges. Ce procédé est articulé autour d'une technique de connexion électrique fiable dans un environnement de boue [8].

Aujourd'hui, pratiquement toutes les diagraphies disponibles peuvent être enregistrées dans les puits horizontaux (à Rospo Mare on dispose de CBL, GR, CCL dans le cuvelage, de ISF, BHC, VDL, GR, BGT, DLL en trou ouvert, et d'une combinaison densité-neutron à travers tiges). Les diagraphies effectuées à Lacq 91 ont permis de représenter précisément une zone très fracturée afin de mettre en place un équipement sélectif de production. Leur qualité est excellente, ainsi qu'en témoigne la figure 1 où l'on voit nettement une zone fissurée, événement capital pour l'étude du gisement. Il est vrai qu'il s'agissait de détecter une zone à pertes totales dont les fissures ont d'énormes ouvertures puisqu'elles ont pu absorber deux tonnes de sable. Associées à des carottages, ces diagraphies apportent des informations nouvelles extrêmement intéressantes sur les gisements. Elles permettent en effet de constituer des coupes horizontales pour la première fois et de préciser les variations latérales des faciès et de la répartition des hydrocarbures.

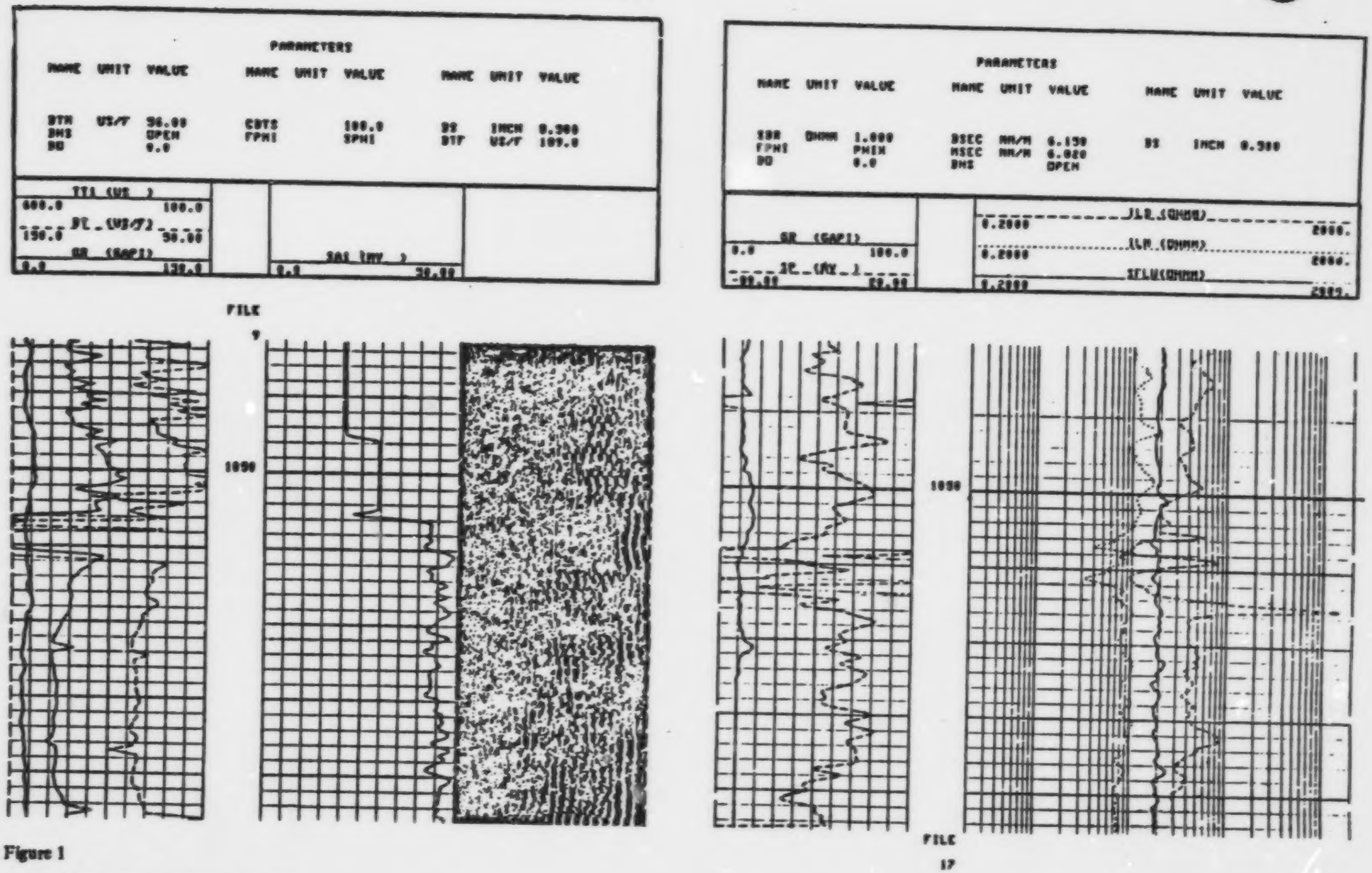

Figure 1

Diagraphies du puits horizontal Lacq 91.

Logs of the Lacq 91 horizontal well.

La zone fracturée située entre 1 051 et 1 056 m apparaît nettement sur ces diagraphies de bonne qualité. Sur le VDL, la zone sombre indique la forte atténuation du signal. Sur la représentation des temps de transit, les décrochages dénotent des sauts de cycles caractéristiques. Les mesures d'induction accusent également des variations importantes. Pour l'interprétation, il a été nécessaire de descendre la courbe d'intensité du signal de 3,5 m et de remonter la courbe de rayon gamma de 1,6 m afin de les remettre en profondeur.

L'effet de l'anisotropie de perméabilité, puis de fractures verticales disposées sur la longueur du puits horizontal sera analysé. Ensuite, une approche synthétique à l'échelle du champ fera appel à la notion de densité de puits et permettra l'analyse comparée du développement de champ par puits verticaux ou horizontaux.

Les mécanismes de production multiphasiques où interviennent des déformations des surfaces de séparation sont ensuite étudiés pour des puits verticaux et horizontaux afin d'évaluer l'avantage que procurent ces derniers eu égard à plusieurs critères.

2. PRODUCTIVITE DES PUITS HORIZONTAUX

Pour les gisements peu épais, la longueur productive d'un puits horizontal n'est pas limitée a priori alors qu'elle l'est par l'épaisseur de la couche pour un puits vertical. Toutefois, comme nous allons le voir, la productivité croît beaucoup plus lentement que la longueur productive (loi en logarithme). Cette possibilité d'augmenter la productivité des puits par le forage de drains horizontaux a été étudiée depuis déjà longtemps et des résultats de calculs et d'expériences sont disponibles dans la littérature [9 à 14]. Un certain nombre de résultats exprimés sous forme analytique permettent de calculer la productivité de puits horizontaux isolés ou disposés en étoile.

2.1. Couche homogène isotrope

Dans un premier temps et pour simplifier, nous supposerons que l'écoulement est plan. Ceci revient à supposer que l'épaisseur de la couche est de l'ordre du diamètre du drain (fig. 2a). Ceci revient aussi à négliger la perte de charge due à la convergence des lignes de courant dans l'écoulement radial circulaire au voisinage du drain vu dans le plan perpendiculaire à celui-ci. Le drain est alors assimilé à une fracture verticale qui recouperait toute l'épaisseur du réservoir.

L'indice de productivité (4) d'un puits horizontal court relativement au rayon de drainage admet, suivant les hypothèses faites, l'expression (1)(5) [15] :

$$IP_H = \frac{2\pi k}{\mu} \frac{h}{\mathrm{Log}\left(\dfrac{1 + \sqrt{1 + (\ell/2r_e)^2}}{\ell/2r_e}\right)} \quad (1)$$

Quand $\frac{\ell}{2r_e}$ est petit, il est licite de négliger ce rapport dans le terme $\sqrt{1 + \left(\frac{\ell}{2r_e}\right)^2}$. L'expression de l'indice de productivité se simplifie alors en :

$$IP_H = \frac{2\pi k}{\mu} \frac{h}{\mathrm{Log}\left(\dfrac{4\,r_e}{\ell}\right)} \quad (2)$$

En première approximation, le rayon d'un puits vertical, équivalent à un puits horizontal qui pourrait être assimilé à une fracture verticale atteignant les épontes est égal au quart de la longueur de ce dernier. Ceci montre bien que l'indice de productivité croît suivant une loi qui dépend du logarithme de sa longueur productive.

Nous retrouvons les résultats que Prats *et al.* [16] puis Duns *et al.* [17] ont obtenu dans une démarche où l'étude des gains de productivité est basée sur le concept de rayon équivalent (r') étendu aux forages inclinés et également aux fractures verticales de hauteur limitée.

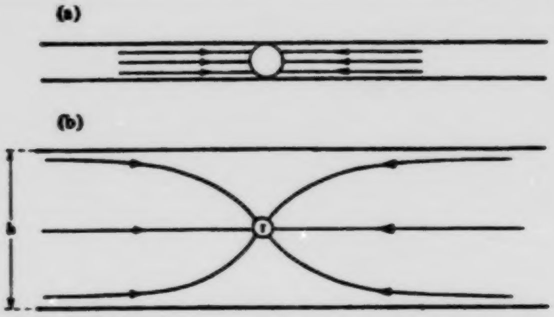

Figure 2

Coupes perpendiculaires à l'axe du drain montrant la concentration des lignes de courant à son voisinage.

Cross-section perpendicular to the axis of the horizontal well, showing the concentration of stream lines in its vicinity.

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(4) C'est le rapport entre le débit produit par puits et la pression de soutirage appliquée au fond de ce puits par rapport à la pression moyenne qui régnerait dans le gisement sur la zone qu'il draine à l'arrêt de la production.

(5) Si l'on veut utiliser les formules de productivité avec des unités pratiques (m^3/j/bar, cP, mD, m), il faut introduire dans le terme de droite le coefficient multiplicatif 0,0233.

Dans ce dernier cas, et tant que la hauteur relative de la fracture h_f par rapport à l'épaisseur de la couche h reste inférieure à son extension latérale $2X_f$ i.e. $h - h_f < 2X_f$, on a :

$$r' = \frac{X_f}{2}\left[\sin\left(\frac{\pi h_f}{2\,h}\right)\cos\left(\pi\frac{\delta}{h}\right)\right]^{h/2X_f} \qquad (3)$$

où δ est la distance verticale entre le milieu de la couche et le centre de la fracture.

Cette relation reste vraie pour un puits incliné (fig. 3), à condition de prendre :

$$\begin{aligned} 2X_f &= \frac{h}{\cos\alpha} \\ H_f &= 4r \qquad (4) \\ \delta &= 0{,}35\,h \end{aligned}$$

avec, en plus, $\alpha \geqslant 20°$.

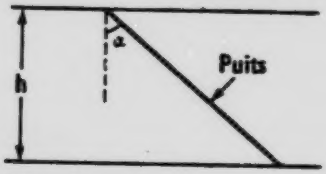

Figure 3
Puits producteur incliné.
Slanted production well.

Pour rendre compte de manière plus exacte de la convergence des lignes de courant dans l'écoulement radial circulaire au voisinage du puits horizontal vu dans le plan normal à celui-ci (fig. 2b), il faut tenir compte d'une perte de charge supplémentaire, ce qui donne pour expression de l'indice de productivité d'un puits horizontal court devant le rayon de drainage (5) :

$$IP_H = 2\pi\frac{k}{\mu}\,\frac{1}{\frac{1}{h}\,\mathrm{Log}\left(\frac{1+\sqrt{1+(\ell/2r_e)^2}}{\ell/2r_e}\right)+\frac{1}{\ell}\,\mathrm{Log}\left(\frac{h}{2\pi r}\right)} \qquad (5)$$

Dans l'article intitulé «Réduction du nombre de puits par l'utilisation de forages horizontaux» [18], F. Giger justifie cette expression et propose des abaques permettant de trouver le rayon d'un puits vertical équivalent à un puits horizontal pour diverses épaisseurs de couche homogène isotrope. Nous utiliserons cette méthode dans un exemple traité ci-après.

2.2. Couche homogène anisotrope

Le mécanisme des dépôts sédimentaires qui ont participé à la formation de la matrice du réservoir et les contraintes tectoniques qui l'ont parfois fracturée sont deux des facteurs principaux qui expliquent les différences entre les valeurs de la perméabilité mesurées suivant plusieurs directions sur un échantillon donné de la roche d'un réservoir.

Pour la représenation des gisements, la pratique fait intervenir l'anisotropie de perméabilité verticale (k_v/k_h) et éventuellement l'anisotropie de perméabilité horizontale (k_x/k_y) selon les directions principales où cette dernière prend les valeurs extrêmes. Nous savons que le potentiel d'un écoulement permanent incompressible admet un laplacien nul. La nature de cette relation permet de faire correspondre à un écoulement dans un milieu où les perméabilités selon les axes principaux sont k_i ($i = x$, y ou v), un écoulement dans un milieu à perméabilité unique k. Il suffit pour cela de dilater les coordonnées selon chacun des axes selon le rapport $(k/k_i)^{1/2}$ d'après Muskat [19].

L'exemple traité ci-dessous(6) montre qu'un rapport k_v/k_h inférieur à 1 est défavorable au

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(6) A titre d'illustration, traitons l'exemple suivant :
Puits horizontal :

$l = 500$ m ; $r_e = 1000$ m ; $k_h = 400$ mD ;
$h = 40$ m ; $k_v = 25$ mD ; $r = 0{,}12$ m.

Nous choisissons $k' = \sqrt{k_v k_h}$. Il vient :

$$k' = \sqrt{k_v k_h} = 100 \text{ mD}$$

l'affinité à effectuer verticalement aura pour facteur :

$$\left(\frac{k'}{k_v}\right)^{1/2} = \left(\frac{100}{25}\right)^{1/2} = 2$$

l'affinité à effectuer horizontalement aura pour facteur :

$$\left(\frac{k'}{k_h}\right)^{1/2} = \left(\frac{100}{400}\right)^{1/2} = 1/2$$

Le cas traité revient donc à :

$l' = 250$ m ; $k' = 100$ mD ;
$h = 80$ m ; $r' = 0{,}12$ m.
$r'_e = 500$ m ;

Pour le rayon, il est licite ici de considérer qu'il ne change pratiquement pas, i.e. $r' = r$. En effet, par l'affinité définie ci-dessus, la section circulaire du puits, vue dans un plan normal à celui-ci, devient une ellipse de grand axe vertical 0,24 m et de petit axe horizontal 0,06 m. Un raisonnement analogue à celui qui conduit à la relation (3) figurant dans le paragraphe 2.1 pour un puits équivalent à une fracture dont le rayon est le quart de l'extension de cette dernière peut être établi. L'ellipse de grand axe 0,24 m équivaut à un cercle de rayon 0,12 m.
Remarquons par ailleurs que si nous avions eu à considérer un puits vertical de rayon $r = 0{,}12$ m, il aurait été transformé par l'affinité en un puits de rayon moitié, $r' = 0{,}06$ m, et producteur sur une hauteur double.

puits horizontal car il équivaut à en raccourcir la longueur. Si une anisotropie de perméabilité horizontale peut être déterminée en grandeur comme en orientation, l'emplacement du puits horizontal doit être choisi afin de faire coïncider l'axe de celui-ci avec la direction de la plus faible perméabilité. Si cette anisotropie de perméabilité horizontale est due à une fissuration selon des plans verticaux, cela revient à placer le drain horizontal perpendiculairement aux fissures, de façon à lui en faire recouper un maximum.

2.3. Forage horizontal multifracturé

Au cours des études et travaux de laboratoire entrepris par la *Compagnie Shell* pour améliorer la productivité des puits forés dans les réservoirs de craie compacte, Duns *et al.* [17] ont calculé qu'un forage horizontal tubé de longueur ℓ équipé de cinq petites fractures verticales (la largeur de chaque fracture étant 0,075 ℓ) a un rayon équivalent pratiquement identique à celui d'une fracture verticale de largeur ℓ(7). Ceci signifie que la simulation d'un puits horizontal pourrait être réalisée avec seulement cinq petites fractures réparties sur sa longueur et recoupant toute l'épaisseur du gisement.

Avec l'aide de la *Compagnie Franlab Consultant*, nous avons développé un modèle pour préciser ce résultat en réalisant de nombreuses simulations.

La figure 4 représente le cas le plus général d'un forage horizontal multi-fracturé drainant une couche parallélépipédique. Cette représentation a été simplifiée à partir d'un certain nombre d'hypothèses faites sur la géométrie du système, sur la position du puits horizontal et des fractures :

– le drain horizontal (r = 0,10 m) est supposé foré au centre de gravité de la section verticale dont les dimensions sont fixées à :

h = 50 m ;
$2L$ = 400 m ;

– les fractures sont équidistantes (distance entre elles : $2D$) les unes des autres et leur succession se répète à l'infini. D'autre part, ces fractures sont de forme rectangulaire et recoupent le toit et le mur du réservoir.

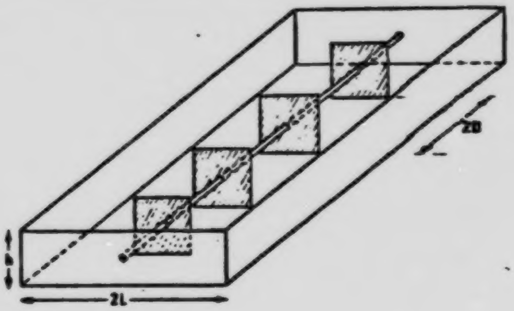

Figure 4

Forage horizontal multi-fracturé drainant une couche parallélépipédique.

Multifractured horizontal well producing from a parallelipipedic payzone.

La conductivité de la fracture étant supposée infinie, le potentiel hydraulique sera le même dans la fracture et dans le puits dans lequel, en outre, les pertes de charges sont négligées. Toutes les autres limites du domaine simulé sont fermées (flux normal nul).

Voyons les résultats obtenus par les simulations conduites avec ce modèle.

2.3.1. Intérêt du puits horizontal par rapport à un puits vertical fracturé

Les deux configurations comparées dans ce paragraphe sont schématisées sur la figure 5. Les résultats sont présentés sur cette même figure sous la forme d'un réseau de courbes:

$$\frac{IP_H}{IP_{VF}} = f\left(\frac{X_f}{L}, \frac{D}{L}\right)$$

Cette figure met en évidence les points suivants:

1) Lorque $\frac{D}{L} < 0{,}25$, le puits vertical fracturé est toujours plus intéressant que le puits horizontal.

2) Dès que $\frac{D}{L} > 0{,}50$, le paramètre essentiel de la comparaison est constitué par l'extension latérale de la fracture $\frac{X_f}{L}$. Ainsi, l'égalité entre IP_H

---

(7) Il s'agit de calculs théoriques. La réalisation pratique de telles stimulations dans des puits horizontaux est encore du domaine de la recherche. Nous ne l'avons pas tentée dans le cadre de notre projet et, à notre connaissance, *Shell* n'a pas expérimenté ce concept sur puits.

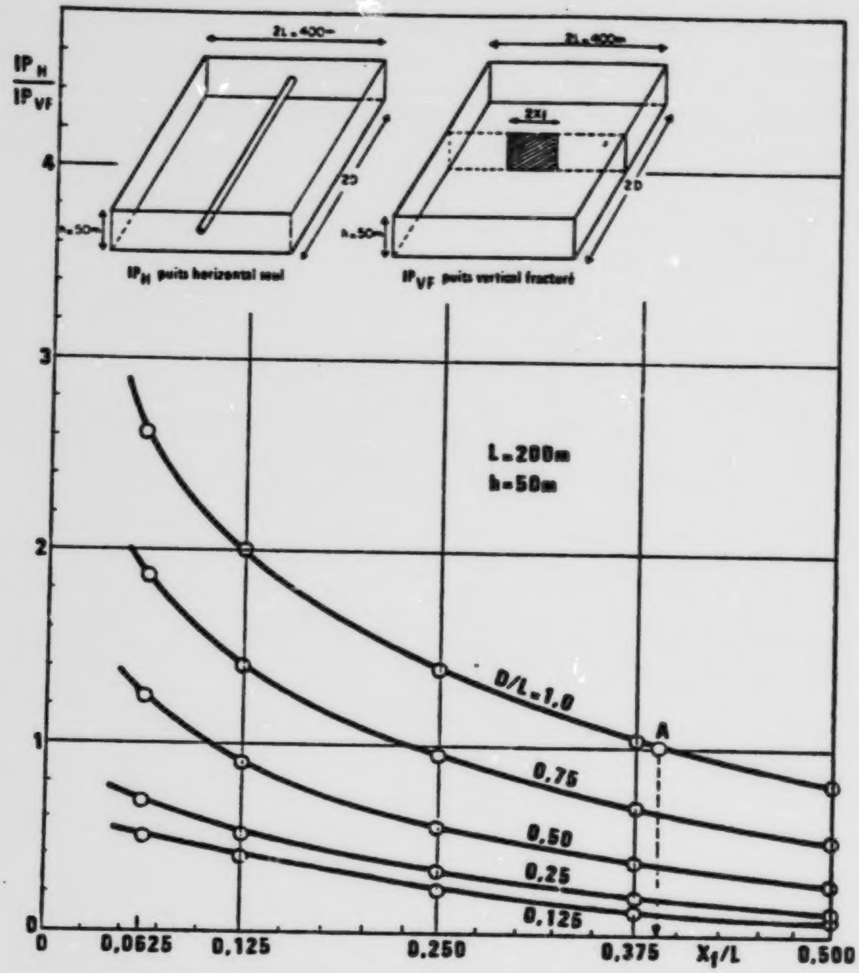

Figure 5

Intérêt du puits horizontal par rapport à un puits vertical fracturé.

Advantage of a horizontal well compared with a fractured vertical well.

et IP_{VF} est obtenue pour $\frac{X_f}{L} = 0{,}39$ lorsque $\frac{D}{L} = 1$ (point A de la fig. 5), pour $\frac{X_f}{L} = 0{,}23$ lorsque $\frac{D}{L} = 0{,}75$ et pour $\frac{X_f}{L} = 0{,}1$ lorsque $\frac{D}{L} = 0{,}5$.

2.3.2. Valorisation du puits horizontal par des fractures

Compte tenu des observations du paragraphe précédent, la fracturation du puits horizontal est susceptible de prendre une grande importance.

Les deux configurations étudiées sont schématisées sur la figure 6. Les résultats sont présentés sur cette même figure sous la forme d'un réseau de courbes :

$$\frac{IP_{HF}}{IP_H} = f\left(\frac{X_f}{L}, \frac{D}{L}\right)$$

Pour mieux illustrer le degré de fracturation du puits horizontal, les courbes sont paramétrées non seulement en fonction de $\frac{D}{L}$, mais également en nombre de fractures par longueur de 400 m de drain.

La figure 6 montre que pour tripler la productivité d'un puits horizontal dans la configuration étudiée, il faut :

- au moins 2 fractures par longueur de 400 m de puits horizontal ;

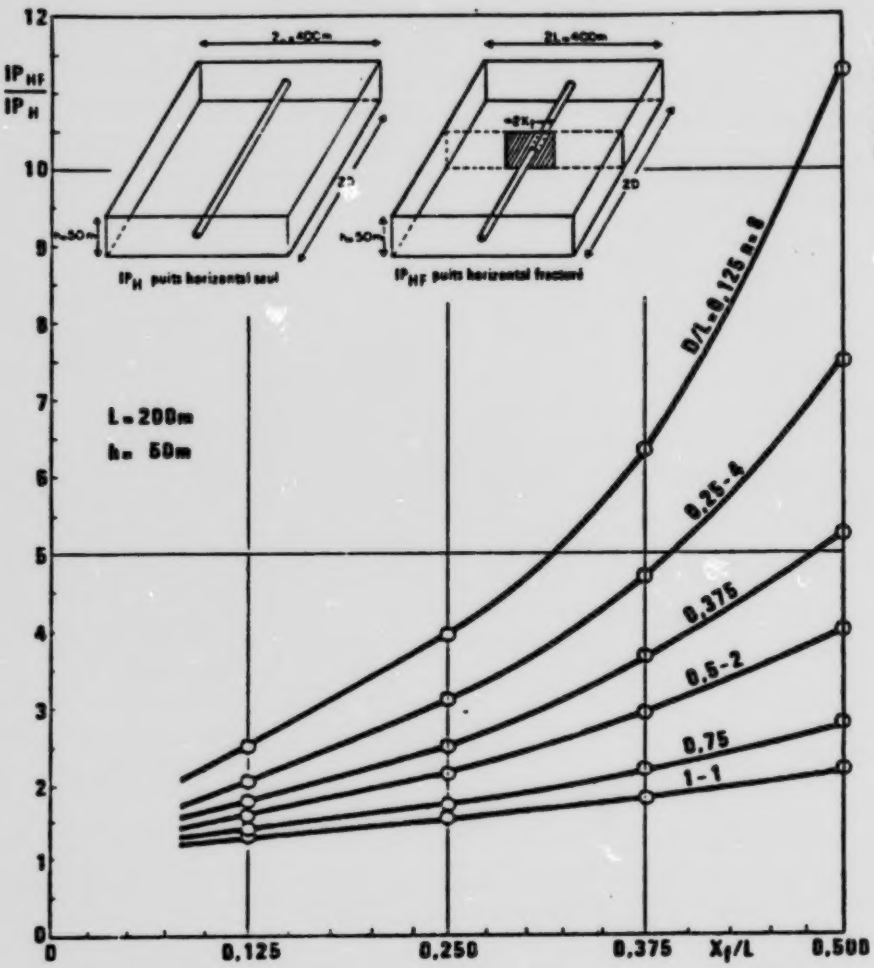

Figure 6

Valorisation du puits horizontal par des fractures.

Improving a horizontal well by fracturing.

– que l'extension latérale des fractures représentée par $\frac{X_f}{L}$, soit supérieure à 0,4 dans le cas de deux fractures, à 0,250 dans le cas de quatre fractures et supérieure à 0,175 dans le cas de huit fractures.

2.3.3. Intérêt du puits horizontal fracturé par rapport à un seul puits vertical fracturé

Cette comparaison a été effectuée dans le cas d'un gisement de 400 x 400 x 50 m. Elle est illustrée par le rapport de l'index de productivité d'un puits horizontal fracturé verticalement (1, 2, 4, 8 et 16 fractures équidistantes) à celui d'un puits vertical fracturé dans les mêmes conditions :

$$\frac{IP_{HF}}{IP_{VF}} = f\left(\frac{X_f}{L}, \text{nombre de fractures du drain}\right)$$

La figure 7a représente les variations de $\frac{IP_{HF}}{IP_{VF}}$ en fonction de ces deux paramètres. Ce réseau montre que tant que le nombre de fractures reste inférieur ou égal à 4, le gain de productivité reste toujours supérieur au nombre de fractures du drain. Par contre, si l'on continue à augmenter le nombre de fractures, un effet de saturation semble apparaître et le gain d'indice de productivité est alors beaucoup plus lié à la taille des fractures qu'à leur nombre.

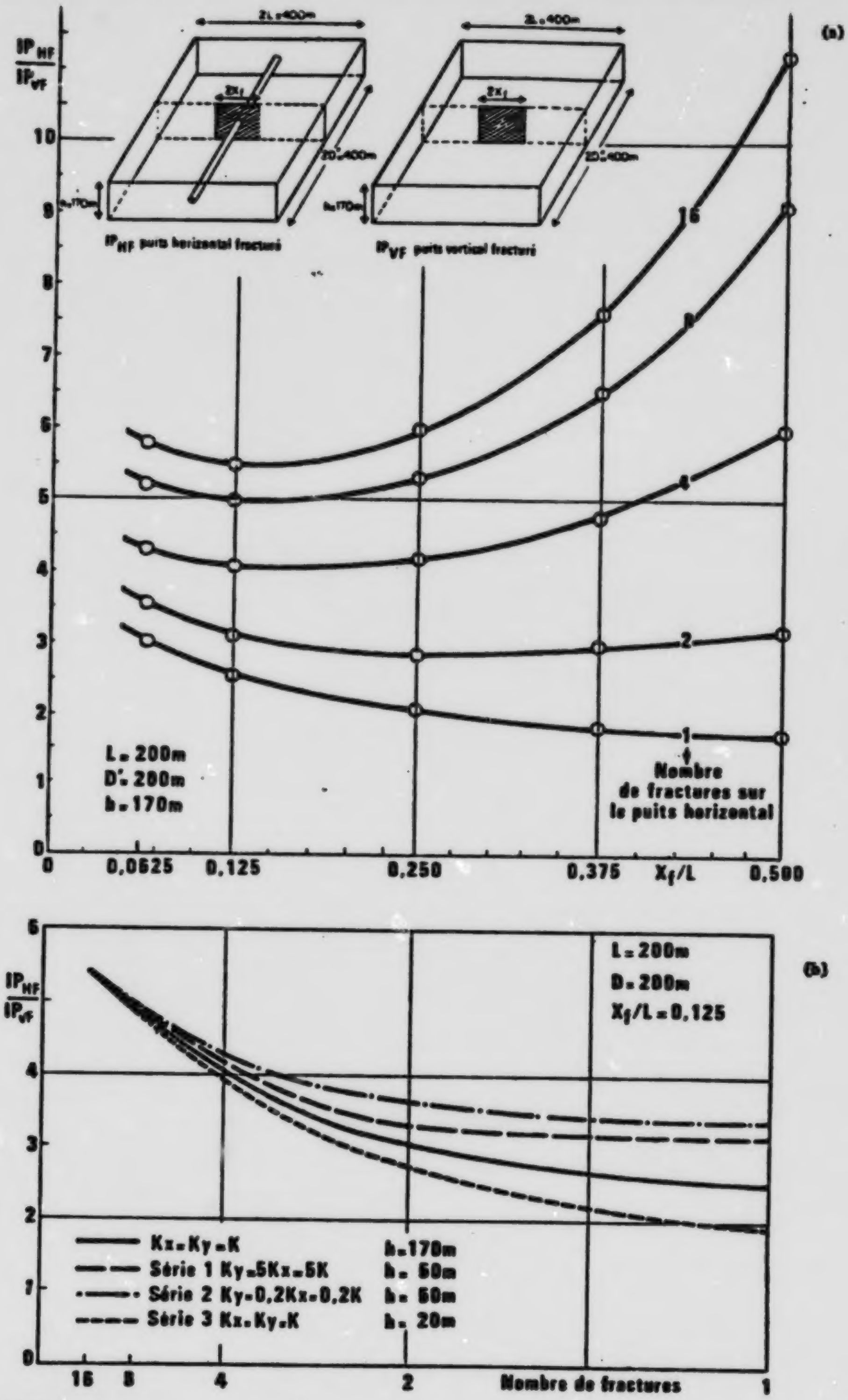

Figure 7

Intérêt du puits horizontal fracturé par rapport à un puits vertical fracturé.
(a) Effet de l'espacement entre fractures. (b) Effet de l'anisotropie et de l'épaisseur du réservoir.

*Advantage of a fractured horizontal well compared to a fractured vertical well.
(a) Effect of the distance between fractures. (b) Effect of the anisotropy and the reservoir thickness.*

La figure 7a concerne les cas de base définis par :

$L = 200$ m ;
$D' = 200$ m (nombre de fractures variable) ;
$h = 170$ m ;
$k_x = k_y = k$.

D'autre part, l'influence de l'épaisseur et de l'anisotropie apparaît sur la figure 7b. La comparaison des séries de simulations avec le cas de base pour lequel la perméabilité est isotrope met en évidence :

- l'effet défavorable d'une détérioration de la perméabilité verticale sur la productivité du puits horizontal fracturé (*cf.* paragr. 2.2) :
- le gain de productivité du puits horizontal fracturé introduit par une augmentation de la perméabilité verticale (pouvant correspondre à des fractures naturelles verticales) et par une réduction de la hauteur de la couche drainée.

2.3.4. Conclusions de l'étude sur modèle des puits fracturés

Cette étude de sensibilité du comportement du puits horizontal multifracturé a permis de situer les domaines dans lesquels il pourrait être attractif. Il est intéressant de noter que le rapport entre l'indice de productivité de ce dernier et celui d'un puits vertical fracturé est analogue à celui obtenu quand ces puits ne sont pas fracturés, puisqu'il s'élève à quelques unités.

2.4. Développement d'un champ avec des puits horizontaux

Considérons maintenant un champ pétrolier à terre, où la seule difficulté serait liée à l'obtention d'une productivité suffisante sur le plan économique. L'outil d'analyse habituellement utilisé est l'indice de productivité. Dans l'expression de l'indice de productivité de chaque puits interviennent des grandeurs imposées par la nature, à savoir : la perméabilité de la roche du réservoir, la géométrie de ce dernier, la viscosité des fluides présents dans cette roche et la nature de l'écoulement. Quant aux paramètres sur lesquels interviennent les responsables du développement du champ, ils résument la géométrie de l'ouvrage de production par le rayon du puits vertical équivalent (puits vertical, incliné ou horizontal, éventuellement cimenté, colmaté, stimulé ou fracturé) et la disposition de chacun par rapport à ses voisins ou aux limites du gisement (frontières, discontinuités, barrières) par le rayon de drainage.

Si l'on désire améliorer les caractéristiques économiques d'un projet en modifiant la géométrie des ouvrages, c'est-à-dire en remplaçant par exemple des puits verticaux par des puits inclinés, fracturés ou horizontaux, il conviendra également de revoir l'espacement entre ces ouvrages. L'indice de productivité n'est alors plus le bon critère d'analyse. F. Giger propose d'introduire la notion d'indice de productivité surfacique qui est le produit de l'indice de productivité par la densité de puits ou nombre de puits par unité de surface [18]. Cette notion permet d'établir des comparaisons entre différents schémas de développement d'un même champ et de mettre en évidence la réduction que l'on peut obtenir sur le nombre de puits grâce à l'augmentation des capacités productives de chacun. Il suffit de connaître les coûts comparés à un moment donné sur un site donné pour effectuer le choix économique entre les variantes.

La démarche proposée est d'autant plus nécessaire que le recours aux puits horizontaux modifie l'ordre de grandeur des rayons de puits verticaux équivalents que l'on a coutume de manier en ingénierie de réservoir, puisque l'on a affaire à des rayons équivalents exprimés en dizaines de mètres au lieu de dizaines de centimètres. L'influence des phénomènes d'interférence devient considérable. Pour l'illustrer, la figure 8 montre l'indice de productivité de drains rayonnants en étoile calculé selon la formule de Borisov [13] :

$$IP = \frac{n\pi k}{\mu} \frac{1}{\frac{1}{h} \mathrm{Log} \left(\frac{1 + \sqrt{1 + (\ell/r_e)^n}}{(\ell/r_e)^{n/2}} \right) + \frac{1}{\ell} \mathrm{Log} \frac{h}{2\pi r}} \qquad (6)$$

On voit sur la figure 8 que l'indice de productivité d'une étoile à 4 branches ou plus n'est guère supérieur à celui d'une étoile à trois branches de même longueur.

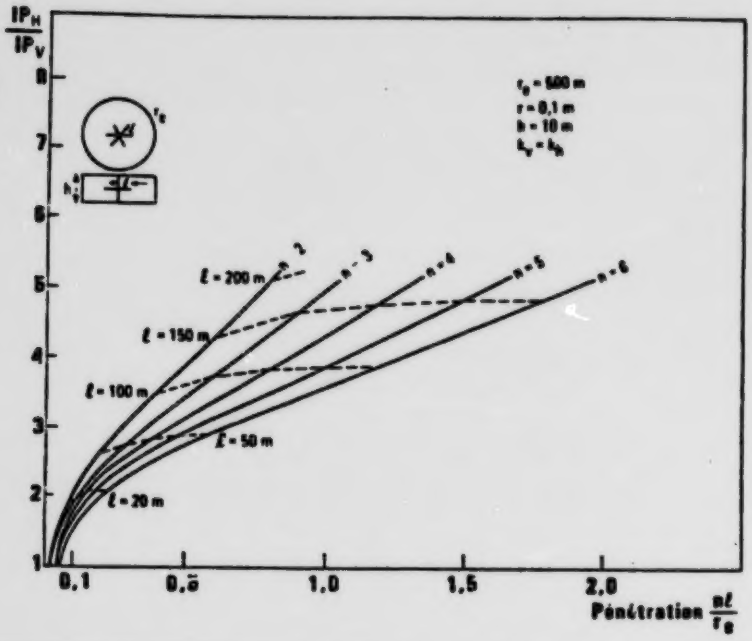

Figure 8

Puits horizontaux en étoile. Influence du nombre de branches.

Star-shaped drainage pattern. Influence of the number of branches.

2.5. Etude de cas réels : indices de productivité mesurés sur des puits horizontaux

Les deux premiers puits horizontaux forés dans le cadre du projet sur le champ de Lacq supérieur, ont eu pour objet principal de mettre au point les techniques de forage [7 bis]. Leurs implantations n'ont donc pas été principalement déterminées selon des critères de gisement. Néanmoins, ces puits nous permettent d'appliquer sur un cas concret à l'échelle un la validité de nos méthodes de calcul de l'indice de productivité.

Traitons par exemple le cas du puits Lacq 90 pour lequel nous disposons de données de production collectées sur une période supérieure à deux ans.

Valeurs numériques :

k ~ 10 mD ;
h ~ 100 m ;
μ ~ 0,5 cP, le champ est noyé et la teneur en huile produite sur les puits n'excède pas 10 % ;
r ~ 0,10 m ;
L ~ 300 m ;
r_e ~ 1 000 m, compte tenu de l'extension de la zone du champ de Lacq Supérieur où le puits est implanté.

L'application de la méthode des abaques [18] ou de la formule de Merkulov donne un rayon équivalent de puits vertical $r' = 15$ m, d'où, en appliquant la relation (7) :

$$IP_V = \frac{2\pi k h}{\mu} \frac{1}{\operatorname{Log}\left(\frac{r_e}{r'}\right)} \tag{7}$$

Soit, en introduisant le coefficient pratique de 0,0233 pour obtenir le résultat en m³/j/bar :

$$IP = \frac{0{,}0233 \times 2 \times 3{,}14 \times 10 \times 100}{0{,}5} \frac{1}{\operatorname{Log}\left(\frac{1000}{300}\right)}$$

$IP = 5{,}8$ m³/j/bar

Cette valeur est à comparer avec celle obtenue sur le puits Lacq 90 qui est de 6,5 m³/j/bar. L'indice de productivité du puits Lacq 90 est environ 4 fois plus grand que la moyenne des puits verticaux voisins.

Notons également que le puits horizontal du champ de Rospo Mare qui a traversé sur une longueur dépassant 600 m un réservoir karstique donc très hétérogène, donne des résultats encore meilleurs. Selon les mesures récemment recueillies au début des essais de production, l'indice de ce puits est plus de dix fois supérieur à ceux des puits voisins.

Le suivi de la production de l'ensemble des puits horizontaux forés au cours de ce projet ou ultérieurement permettra de confronter les calculs théoriques aux résultats de champ sur un nombre plus important de cas. Toutefois, les résultats acquis nous permettent déjà d'être confiants sur la validité des calculs théoriques de productivité.

3. ETUDE DE LA PRODUCTION DANS LES CAS DE DEFORMATION DE FRONTIERES ENTRE ZONES ENVAHIES PAR DES FLUIDES DIFFERENTS

3.1. Calculs analytiques de débit critique

3.1.1. Puits verticaux

Dans les gisements où existe initialement une frontière horizontale gaz-huile ou eau-huile, il se produit, lors du soutirage par un puits proche de celle-ci, une déformation (effet de cône) qui peut entraîner une percée du gaz ou de l'eau et une production diphasique (fig. 9). Cet effet de cône a été étudié depuis longtemps mais n'a pas jusqu'à présent été résolu exactement par la voie analytique. Seules existent dans la littérature des formules approchées, bâties à partir de groupements typiques des variables physiques tels qu'ils apparaissent dans un modèle simplifié destiné à évaluer la dépression dynamique créée par l'écoulement radial circulaire horizontal [20]. Les résultats sont d'autant plus approchés que la garde à l'eau initiale est élevée, que la zone ouverte du puits est limitée et que l'on s'en trouve près. Les résultats sont souvent présentés sous la forme :

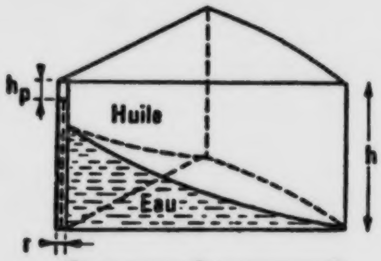

Figure 9
Effet de cône à l'eau.
Waterconing.

$$Q_c = \beta \frac{k_h \; \Delta p \, h(h - h_p)}{\mu} \qquad (8)$$

(où, en unités pratiques, $\beta = 0{,}00124$ ou $0{,}00152$ selon les auteurs).

Cette formule met en évidence un paramètre important : la différence $h - h_p$ entre les cotes du bas des perforations et du plan d'eau initial (garde à l'eau). En fait, le débit critique dépend aussi de la géométrie du réservoir : en particulier, il décroît quand le rayon de drainage augmente, ainsi que le montre la corrélation de Chierici [21] : lorsque le rayon de drainage est supérieur de 5 à 10 fois la hauteur d'huile, le débit critique en devient pratiquement indépendant.

Pour mémoire, citons également d'autres formules où la prise en compte de l'écoulement radial circulaire fait intervenir un potentiel dans l'expression duquel le rayon de drainage apparaît à l'intérieur d'une fonction logarithme [12].

Pour l'application pratique de ces formules, des écarts importants sont souvent constatés entre les calculs et les mesures sur champ. La nature du problème physique implique que les résultats effectifs sur champ dépendent très fortement des hétérogénéités de la roche réservoir aux abords immédiats et sous le puits.

Néanmoins, ces formules trouvent une utilisation pratique sur le terrain après calage d'une constante multiplicative propre à un ensemble de puits producteurs. Elles permettent une approche relativement satisfaisante des tendances variationnelles lors de la modification des paramètres significatifs pris en compte.

Pour l'étude des paramètres adimensionnels, les travaux analytiques de Muskat [22] font apparaître trois paramètres adimensionnels caractéristiques dans ces configurations :

- le rayon de drainage adimensionnel :

$$r_{eD} = \frac{r_e}{h} \sqrt{\frac{k_v}{k_h}} \qquad (9)$$

r_e : rayon de drainage, h : hauteur d'huile initiale, k_v et k_h : perméabilités verticale et horizontale ;

– la hauteur perforée adimensionnelle :

$$h_{pD} = \frac{h_p}{h} \tag{10}$$

h_p : hauteur perforée ;

– le rayon de puits adimensionnel :

$$r_D = \frac{r}{h}\sqrt{\frac{k_v}{k_h}} \tag{11}$$

r : rayon du puits.

En régime permanent, ces paramètres adimensionnels suffisent à caractériser le système.

3.1.2. Puits horizontaux

L'idée d'augmenter la garde à l'eau tout en gardant des index de productivité suffisants, a conduit à l'étude du comportement de puits horizontaux forés au toit de la couche productrice, et en particulier de leur débit critique.

L'étude de la surface de contact huile-eau et de l'écoulement de l'huile vers un puits horizontal se prête à l'étude analytique. En effet, il s'agit d'un problème à deux dimensions dans un plan perpendiculaire à l'axe du drain supposé infini.

Dans son article [23], R.E. Kidder traite de la déformation de la frontière dans le cas de la montée d'eau de bordure d'un gisement plan incliné et de faible épaisseur. On peut essayer d'utiliser ces travaux pour étudier le mouvement de la frontière dans le cas du puits horizontal en imaginant que le gisement plan et mince de Kidder pivote et devient vertical pour $\theta = \pi/2$ (fig. 10). Il faut cependant noter que l'absence de limite supérieure pour la zone à huile limite la validité de l'étude au cas du puits horizontal proche de la frontière huile-eau. Néanmoins, cette approche a le mérite de montrer comment la méthode de l'hodographe permet d'atteindre une expression paramétrée exacte de la frontière huile-eau et de déterminer le débit critique.

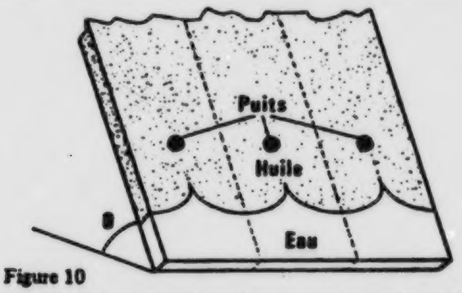

Figure 10

Montée d'eau de bordure d'un gisement plan incliné de faible épaisseur.

Waterfingering in a thin tilted layer.

De son côté, D.A. Efros [24] étudie l'effet d'arête d'eau créé par un drain horizontal situé au toit horizontal d'une couche réservoir avec présence d'eau sous-jacente. La mise en œuvre de la méthode de l'hodographe lui permet d'obtenir par la composition de plusieurs transformations conformes une solution approchée, au prix de quelques approximations de peu d'incidence. Efros parvient à paramétrer l'équation de la frontière huile-eau et à donner la valeur du débit critique. Son approche, qui a été reprise et complétée, est présentée par F. Giger [25].

Ces calculs analytiques fournissent une expression du débit linéique critique qui se simplifie dès que le rapport de l'extension de la zone à huile à sa hauteur h dépasse 5(8) :

$$q_{cr\infty} = \frac{k\,\Delta\rho\, g}{\mu}\,\frac{h^2}{\ell} \tag{12}$$

Si l'on compare cette expression à celle obtenue pour un puits vertical, on voit que le terme $h(h - h_p)$ qui caractérise l'influence de la géométrie du puits vertical sur son débit critique est remplacé ici par le terme $\frac{h^2}{\ell}$. Remarquons que dans le cas du puits horizontal situé contre l'éponte supérieure, l'équivalent du terme h_p est nul et n'a donc pas lieu d'intervenir.

Quant au terme $1/\ell$, c'est celui que l'on obtiendrait en faisant l'approximation de Dupuit [26]. Il s'agit de considérer la perméabilité verticale infinie. On obtient alors comme Kozeny (cité par Muskat [22]) que la surface libre du fluide en mouvement est une surface réglée parabolique, ici $\frac{h^2}{\ell} = \text{Cte}$.

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(8) Si l'on veut utiliser cette formule avec des unités pratiques, il faut introduire dans le terme de droite le coefficient multiplicatif $0{,}837 \times 10^{-3}$.

Ici, un commentaire s'impose au sujet de la forme de la frontière entre l'eau et l'huile à une distance suffisamment grande du puits. Pour les puits verticaux, l'impact de cette distance intervient à l'intérieur de la fonction logarithme. Pour un débit donné et à une distance suffisante, les valeurs prises par cette fonction évoluent peu et l'on considère en général qu'il existe un plan d'eau horizontal. Il en va tout autrement avec les puits horizontaux infinis (ou traversant complètement un gisement dans sa largeur) : l'impact de la distance intervient par le facteur $\frac{1}{\ell}$ dans $\frac{h^2}{\ell}$.

Dans cette schématisation, on n'est plus en droit de considérer qu'il existe un plan d'eau loin du puits.

Ces estimations analytiques du débit critique peuvent être utilisées dans le cas où le puits horizontal infini traverse complètement un compartiment de gisement alimenté latéralement. Dans les autres cas, nous avons utilisé jusqu'à présent des modèles de simulation.

Cependant, il ne faut pas oublier que ces formules permettent de raisonner sur l'influence des différents paramètres.

3.2. Détermination sur modèle numérique du débit critique et du volume balayé correspondant

Dans les paragraphes qui suivent, nous allons expliciter les résultats de nos calculs sur modèle, relatifs au comportement «critique» des puits horizontaux infinis et limités ainsi que sur le comportement «après percée».

3.2.1. Débit critique d'un puits horizontal par unité de longueur ou débit linéique critique

Le modèle Rzmono permet de calculer très rapidement, aussi bien pour le puits horizontal que pour le puits vertical, le débit critique et le volume balayé par la nappe d'eau dans le cas d'alimentation latérale dans les deux phases. Le modèle est vertical, circulaire ou plan (*RZ* ou *XZ*) et suppose qu'il n'y a pas d'écoulement dans la zone envahie par l'eau (hypothèse de Muskat). La position du cône stable est déterminée en écrivant sur la surface de contact huile-eau l'équilibre entre les frottements visqueux et les forces de gravité.

Le faible coût et la rapidité d'emploi de ce modèle ont permis de réaliser un grand nombre de simulations en faisant varier le rayon de drainage, la hauteur d'huile et le rapport d'anisotropie dans une gamme assez large.

Plus de cent soixante simulations ont été effectuées, faisant varier pour le puits horizontal infini et le puits vertical la distance à la bordure d'alimentation (100 à 500 m), les hauteurs perforées (1 à 20 % de la hauteur d'huile), les rapports d'anisotropie $\frac{k_v}{k_h}$ (de 1 à 1/100) et la hauteur d'huile (10 à 100 m).

Les principaux résultats obtenus font apparaître que dans la gamme des valeurs étudiées, ni h_{pD} ni r_D n'ont d'influence notable. Ceci est dû au fait que tant que la hauteur perforée à partir du toit de la couche ou la distance du puits horizontal au toit de la couche ne dépassent pas 10 à 20 % de la hauteur d'huile, le puits peut être considéré comme source ponctuelle au toit. Pour les petites valeurs de r_D, c'est-à-dire des espacements entre puits petits, le débit critique croît fortement. Pour les valeurs usuelles de r_D (5 et plus), le débit critique du puits horizontal est de 2 à 3 fois celui du puits vertical.

3.2.2. Volume balayé par l'eau pour un drain infini

Le volume de la nappe d'eau est aussi donné par le modèle et les courbes sont présentées sur la figure 11. Le gain dû au puits horizontal est d'autant plus significatif que l'espacement entre puits est important. Pour les valeurs usuelles de r_D, le volume de la nappe sous le puits horizontal, et par conséquent la récupération, sont 4 à 6 fois plus élevés que pour le puits vertical (voir fig. 12). Avec les hypothèses de calcul de ce modèle, ce volume représente l'efficacité volumétrique du balayage au débit critique.

Les résultats d'efficacité volumétrique obtenus avec le modèle de débit critique peuvent, en première approximation, être considérés comme valables à la percée en régime supercritique puisque l'on sait que le volume sous la nappe à la percée est peu différent de celui calculé au débit modérément critique.

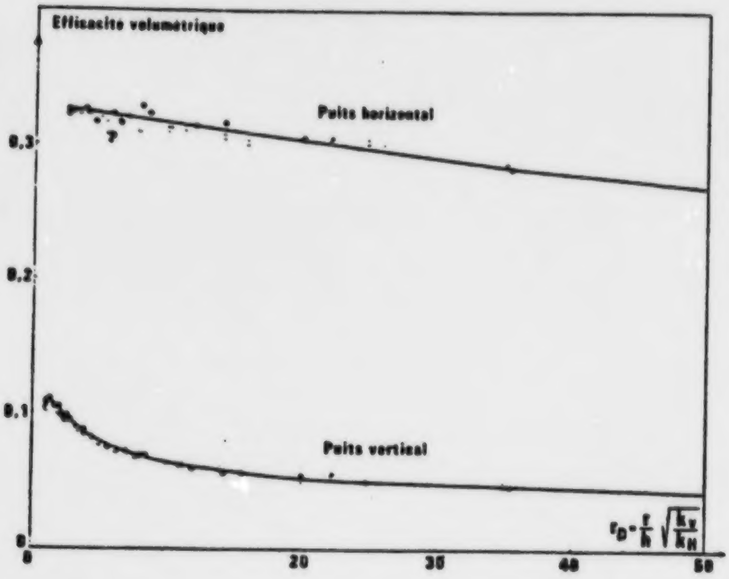

Figure 11

Efficacité volumétrique de balayage au débit critique.

Volumetric sweep efficiency at critical flow rate.

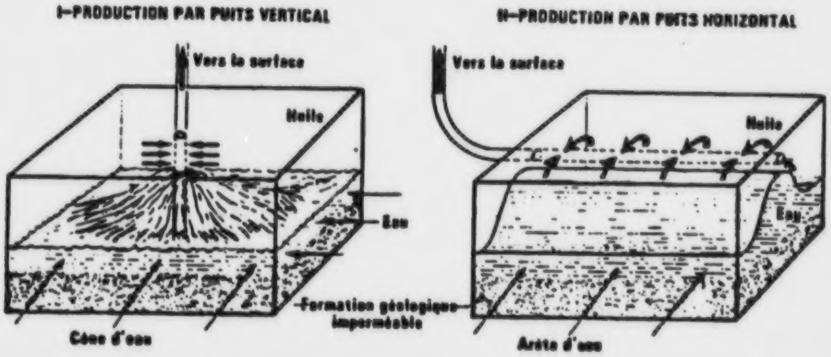
I—PRODUCTION PAR PUITS VERTICAL
Vers la surface
Huile
Eau
Formation géologique imperméable
Cône d'eau
II—PRODUCTION PAR PUITS HORIZONTAL
Vers la surface
Huile
Eau
Arête d'eau

Figure 12

Déplacement de l'huile par l'eau.

Oil drive by water.

3.2.3. Débit critique et efficacité du balayage volumétrique pour un puits horizontal de longueur finie

Pour des raisons économiques, on sera amené à envisager des lignes discontinues de puits horizontaux. L'étude du débit critique a été complétée dans ce but par des cas où le puits horizontal infini est remplacé par une ligne discontinue de puits horizontaux de longueur variable.

Les paramètres géométriques à prendre en compte deviennent alors plus nombreux. On s'est limité au cas d'une ligne de puits horizontaux parallèle à une limite alimentée. Ceci peut représenter la configuration du dispositif en ligne directe (fig. 13). La géométrie du problème est alors caractérisée par 3 paramètres qui peuvent être ramenés à deux groupes adimensionnels : ℓ/a et L/a, L étant la distance entre la ligne de puits horizontaux et la limite alimentée, a étant la distance entre les centres de deux puits voisins et ℓ la longueur d'un puits horizontal.

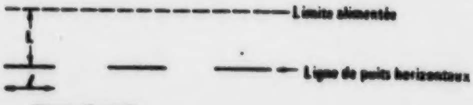

Figure 13

Dispositif de puits horizontaux en ligne directe.

Horizontal wells in direct line-drive pattern.

Le modèle utilisé est la version tridimensionnelle du modèle de débit critique (Muskat 3D), qui permet de représenter des puits horizontaux de longueur finie.

Les résultats montrent (fig. 14) que le débit critique augmente quand la longueur du drain augmente et que cette augmentation est d'autant plus forte que ℓ/a est petit. Des discontinuités faibles dans une ligne de drains (ℓ/a de l'ordre de 0,8 à 0,9) n'abaissent que peu le débit critique, et ceci d'autant plus que L/a est grand.

Définissons l'efficacité volumétrique de balayage E_v comme le rapport du volume balayé par l'eau au volume initial d'huile. L'efficacité volumétrique de balayage croît rapidement avec ℓ/a quand celui-ci est petit. Quand ℓ/a dépasse 1/2, les phénomènes d'interférence entre extrémités de puits horizontaux ne permettent plus de gagner grand chose, du moins pour les valeurs choisies[9].

3.2.4. Etude par simulation du régime supercritique

Pour explorer le domaine des débits supérieurs aux débits critiques, des simulations ont été effectuées avec le modèle triphasique tridimensionnel TRITRI afin de connaître les productions anhydres et hydratées jusqu'à un ennoyage important et avec divers rapports de mobilité des fluides M (fig. 15).

En l'absence de pressions capillaires, on sait que

---

[9] Il s'agit de a = 400 m
ℓ = 400 à 800 m
h = 10 m

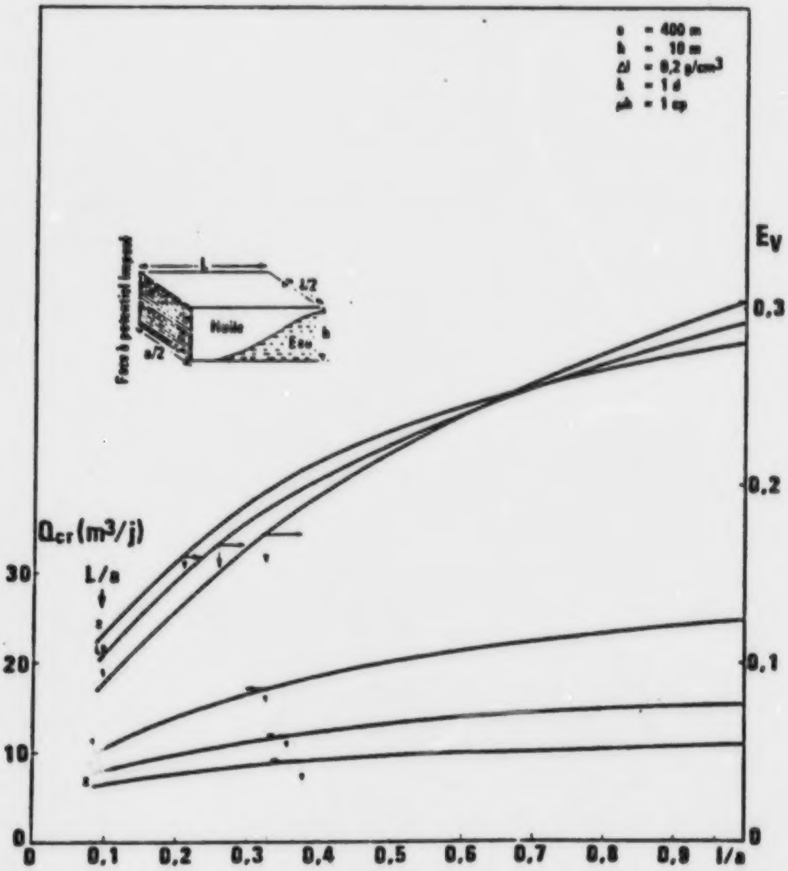

Figure 14

Débit critique et efficacité de balayage volumétrique pour un puits horizontal de longueur finie.

Critical flow rate and volumetric efficiency for a horizontal limited well.

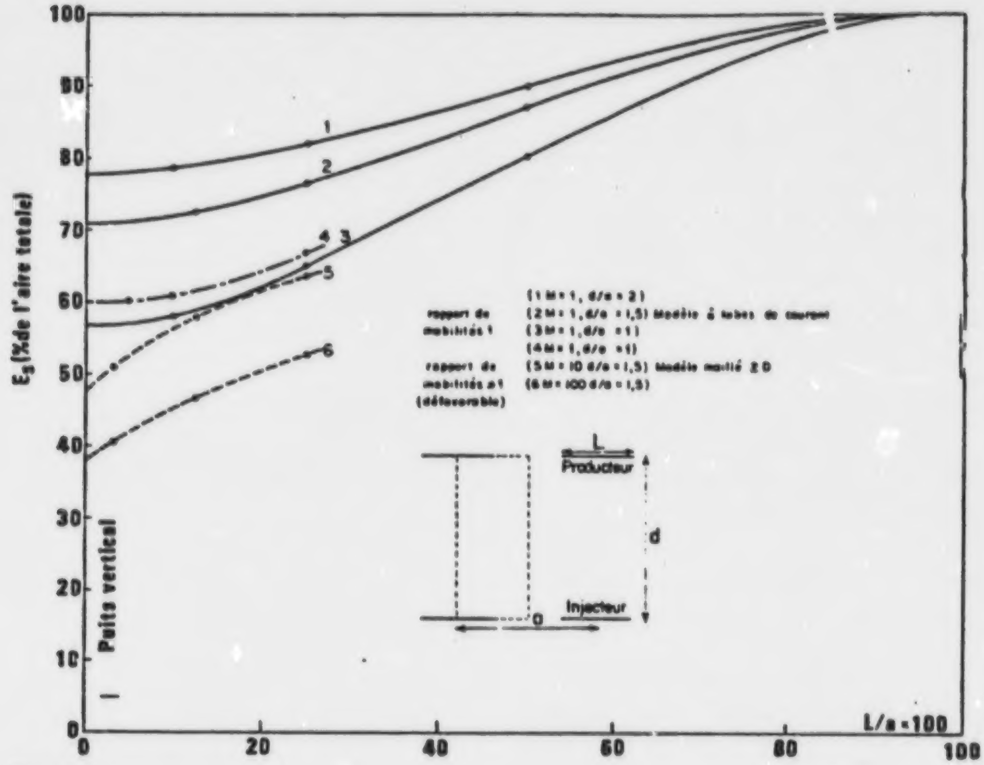

Figure 15

Balayage superficiel par puits horizontaux de longueur finie à régime supercritique.

Superficial sweep efficiency with horizontal wells of varying length (at breakthrough) in a line-drive pattern.

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les paramètres adimensionnels caractéristiques sont [19 et 22] :

$$r_{eD} = \frac{r_e}{h}\sqrt{\frac{k_v}{k_h}} \tag{9}$$

$$h_{pD} = \frac{h_p}{h} \tag{10}$$

$$r_D = \frac{r}{h}\sqrt{\frac{k_v}{k_h}} \tag{11}$$

$$M = \frac{k_{rh}}{\mu_h}\,\frac{\mu_e}{k_{re}} \tag{13}$$

$$N_{pD} = \frac{QT}{r_e^2 h\phi(1 - S_{hr} - S_{ei})} \tag{14}$$

$$R_e = \frac{\mu_h Q_h}{\Delta\rho\, g k_h r_e h} \tag{15}$$

Les trois premiers paramètres sont ceux définis au paragraphe 3.1.1, les trois autres sont le rapport des mobilités, la production cumulée adimensionnelle et le nombre de Reynolds (rapport des forces de gravité aux forces d'inertie).

Dans la simulation, les puits verticaux ou horizontaux sont supposés faire partie d'une implantation répétitive où la maille de base XY est carrée et où les limites sont à flux nul. Le réservoir simulé est à couches planes horizontales.

Pour le puits vertical, le maillage est symétrique en X et en Y et pour le puits horizontal, un maillage bidimensionnel YZ a été utilisé.

3.2.5. Gains de récupération réalisés avec les puits horizontaux

L'efficacité volumétrique de balayage E_v a été obtenue en sommant sur le volume où la saturation en eau est supérieure à la saturation initiale en eau S_{ei}.

Le taux d'interférence à la percée est défini comme étant le pourcentage de la hauteur initiale d'huile envahie par l'eau à la limite de drainage au moment de la percée.

Pour des rapports de mobilité très défavorables, le taux de récupération des puits horizontaux est nettement supérieur à celui des puits verticaux à la percée. Cet avantage se maintient ensuite. Par exemple, un gain de 6 pour $M = 100$.

Pour des rapports de mobilité moins défavorables[10] le gain de récupération des puits horizontaux reste plus grand à la percée, et tend à s'amenuiser pendant la production à pourcentage d'eau élevé. Par exemple, pour $M = 10$, le gain à la percée atteint 3,4 et passe à 1,3 pour un pourcentage d'eau de 80 %.

Au sujet de l'espacement entre puits, le gain à la percée des puits horizontaux par rapport aux puits verticaux est d'autant plus grand que le taux d'interférence entre eux est plus faible. Par exemple, pour $M = 10$, le gain à la percée, qui était de 3,4 pour une interférence nulle, passe à 1,6 pour une interférence importante.

Quant au cas de rapports de mobilité nettement favorables, le gain de récupération, s'il est encore significatif à la percée, devient très faible ensuite. Pour $M = 0{,}5$, il passe de 2,7 à 1,02 entre la percée et 80 % d'eau.

3.3. Efficacité du balayage superficiel

Dans les cas de gisement initialement sans frontière entre fluides près des puits, il existe plusieurs types de réseaux d'injection d'eau, en particulier le dispositif en ligne directe. Dans le cas où la couche est assez mince pour qu'on puisse considérer l'écoulement comme plan, la surface contactée par le fluide pousseur est pratiquement proportionnelle à la récupération jusqu'à la percée.

Les paramètres de calcul de l'efficacité de balayage à la percée sont, pour ce dispositif, le rapport d/a de la distance entre lignes de producteurs et d'injecteurs à la distance entre puits de même nature et le rapport L/a pour les puits horizontaux, rapport de la longueur du puits à la distance entre les centres de deux puits de même nature (voir fig. 15).

Des cas de rapports de mobilités différents ont été étudiés. Lorsque le rapport des mobilités est égal à 1, les simulations ont été effectuées avec un modèle à tubes de courant. Lorsque le rapport des mobilités est défavorable ($M = 10$ et $M = 100$), elles ont été effectuées avec un modèle biphasique bidimensionnel XY.

Des solutions analytiques exactes sont connues dans le cas du puits vertical pour un rapport de mobilité M égal à 1. Des résultats d'expériences sur modèle électrolytique correspondent au cas du puits horizontal : il s'agit de l'étude de l'effet de fractures verticales d'extension limitée se présentant dans le plan XY sous la forme de pointillés. Ce dispositif est équivalent à l'effet d'une série de puits horizontaux sur le balayage superficiel.

Les simulations ont été effectuées avec des rapports d/a de 1 à 2 et L/a de 0 à 0,5.

Le rapport $L/a = 0$ représente le puits vertical classique. Les résultats sont rassemblés sur la figure 15. On constate que le modèle à tubes de courant donne des résultats très proches des solutions analytiques de Muskat dans le cas du puits vertical. Pour le puits horizontal limité, on remarque que lorsque le rapport des mobilités est égal à 1, les résultats diffèrent de ceux tirés de la littérature. En effet, on voit que le gain d'efficacité superficielle de balayage est très faible tant que L/a reste inférieur à 0,1. Le gain dû au puits horizontal est d'autant plus grand que d/a est petit. Ceci contredit les résultats de Crawford obtenus par interpolation sur un nombre insuffisant de points [10].

4. UTILISATION DE PUITS HORIZONTAUX POUR LA MISE EN ŒUVRE DE METHODES DE STIMULATION THERMIQUE

Les industriels canadiens ont foré sur le champ de Cold Lake notamment [6 et 7] des puits horizontaux d'injection de vapeur. L'intérêt attendu d'un tel dispositif est une amélioration de l'efficacité de la stimulation pour les raisons suivantes :

---

(10) Ces valeurs sont données à titre d'indication de tendance et, ayant été obtenues sur un nombre limité de cas particuliers, ne doivent pas être aveuglément utilisées.

– Malgré la viscosité de l'huile en place, l'indice de productivité du puits horizontal est supérieur à celui de puits verticaux. Il permet d'injecter un plus grand débit de vapeur par puits et donc de diminuer l'incidence relative des pertes thermiques sur la colonne d'acheminement de la vapeur.

– Le positionnement du puits d'injection parallèlement aux épontes permet de limiter la proportion des fuites thermiques de la formation vers celles-ci. La vapeur mise en place par un puits horizontal intéresse un volume de gisement a priori plus important que ne le fait celle injectée par un puits vertical ouvert sur toute sa hauteur avant que les fuites hors de la formation ne deviennent prépondérantes.

Les calculs et les essais sur modèles de laboratoires conduits par *Esso Ressources Canada* [5] montrent l'influence de la gravité ; l'ombrelle de vapeur a tendance à se développer vers le haut. De ce fait, il semble judicieux de positionner le puits horizontal injecteur de vapeur vers le bas de la zone à stimuler. C'est ce que *Texaco* a réalisé dans le cadre d'un projet pilote qui est en cours d'exploitation.

5. CONCLUSION

Les études en gisement conduites dans le cadre du projet de forage horizontal à l'aide de travaux théoriques, de modèles et l'interprétation de résultats collectés sur des réalisations industrielles permettent d'établir les enseignements suivants.

Comparé à un puits vertical, le puits horizontal permet d'accroître les débits de production ou d'injection par un facteur multiplicatif de plusieurs unités. Le procédé est à envisager lorsque la fracturation hydraulique réalisée à partir de puits verticaux est inefficace pour telle ou telle raison. Le gain attendu est d'autant plus grand que le réservoir est moins épais et la perméabilité verticale plus élevée. Il peut même atteindre la dizaine dans des réservoirs fissurés ou très hétérogènes ; ce fut le cas pour le puits horizontal foré dans le réservoir karstique du champ de Rospo Mare.

Si une frontière entre plusieurs fluides se trouve dans le gisement à proximité de la zone des puits, la production avec un puits horizontal doit permettre d'améliorer le débit et la récupération d'huile dans un rapport de plusieurs unités grâce à l'augmentation des volumes drainés. Cependant, pour tirer pleinement parti de cet effet favorable, il est nécessaire de réaliser des «complétions» sélectives adaptées aux hétérogénéités spatiales des caractéristiques de la matrice et des fluides du gisement [27].

Pour soutirer de l'huile difficilement accessible, le puits horizontal possède deux atouts : il permet d'augmenter les surfaces de gisement soumises au balayage ; il permet également d'atteindre des régions latérales mal drainées par les puits verticaux.

Les succès répétés des opérations de diagraphie et de carottage apportent de grands progrès dans l'appréciation de l'évolution latérale des faciès et de la distribution des fluides au sein du gisement.

Dans le cadre de la récupération assistée, les puits horizontaux sont susceptibles d'assurer une meilleure mise en place du fluide vecteur, de la vapeur par exemple.

Les axes de recherche et d'expérimentation sont à présent le développement de la complétion sélective et l'expérimentation sur modèle physique d'échelle décamétrique si possible, des écoulements multiphasiques.

Les auteurs tiennent à exprimer leurs remerciements à tous leurs collègues qui ont participé à ce travail d'équipe, et en particulier à C. Jain (*Institut Français du Pétrole*) et O. Ricard (*Elf-Aquitaine*) pour leur talent créateur.

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SESSION I
PAPER 3

(48)

Alberta OIL SANDS
INFORMATION CENTRE

THE FOUR HORIZONTAL WELLS PRODUCING OIL IN WESTERN EUROPE

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THE FOUR HORIZONTAL WELLS PRODUCING OIL IN WESTERN EUROPE

Abstract

Between 1979 and 1983, four horizontal wells, including one offshore, were drilled by Elf Aquitaine in association with the Institut Français du Pétrole and with the financial support of the European Economic Community. These wells, drilled in limestone oil-bearing reservoirs reached vertical depth ranging from 600 meters (1,800 ft) (the first two, at Lacq, France) to 3,000 meters (10,000 ft) (Castéra Lou, France). One of them was been drilled offshore at Rospo Mare in the Italian Adriatic waters.

The aim of these wells was primarily to acquire knowledge in the drilling, completing, logging and testing of horizontal wells and then to demonstrate their superiority in their specific favorable areas.

These goals have been reached :

- For drilling : a horizontal well is not more expensive than two or three vertical wells.
- For logging : almost all available logs have been recorded horizontally. Most of the available logs have been recorded, using a specially designed device, SIMPHOR : γR, Neutron, Induction, Dual Laterolog, Caliper. Their quality is excellent.
- For coring, performed without any problem.
- For production : the good production behavior of horizontal wells confirms the theoretical calculations. According to them, one horizontal well is the equivalent of up to five vertical wells, if the reservoir is homogeneous, and to 10 or more in some fractured or karstic reservoirs.
- For completion : they have been partially reached. External packers have not been satisfactorily set, but a limited horizontal cementation and perforation job was successfully achieved. As far as the completion of these vast wells is concerned, study and work are going on at present as part of this scientific and technical research effort.

Introduction

In North America, horizontal wells are on the way to proving themselves economical compared to vertical wells, when used for enhanced oil recovery, namely in unconsolidated tar sands at shallow depth[1-3].

The approach to horizontal drilling followed in Western Europe has been very different. Our need for a new concept arose when we were deciding how to put into production a deep offshore field with a complex karstic structure[4]. There, the active underlying aquifer is liable to flood quickly any conventional vertical well through the fissures and the big dissolution voids in the tight carbonate matrix. This gave rise to the idea of drilling horizontal wells near the roof of the reservoir to situate them as far as possible from the water-oil contact and of extending them laterally to enable them to achieve high productivity by intersecting a large number of open fissures.

Reservoir engineering incentives

For thin homogeneous deposits, the productive length of a horizontal well is not limited a priori, whereas it is limited by the thickness of the layer for a vertical well.

For fields with little vertical thickness, the productive length of a horizontal well is considerably greater than that of a vertical well. The productivity of a horizontal well increases with its length, although more slowly than this length because a logarithmic pressure-distance law comes into play. Analytical derivations as well as simulations on numerical models show that the increase in productivity may regularly attain a factor of 3 to 5[4]. Nevertheless, if the permeability is not isotropic, a high k_V/k_H ratio is unfavorable to horizontal wells.

In fields having parallel vertical fractures, once the preferential orientation of the cracks has been determined, a horizontal well drilled perpendicularly to these fractures should cut across a great many of them. Considerable gains in productivity can be expected. Gains of the same order of magnitude may also be obtained for heterogeneities other than fissuration, for instance facies lenses that are sought when producing edge or insert oil.

In fields with very heterogeneous permeability, such as karstic reservoirs, a horizontal well has a very good chance of encountering highly productive zones (case of Rospo Mare in Italy where a productivity increase by a factor of 20 was found in comparison with neighboring vertical wells)

In chalk, where massive pore collapse follows high drawdowns, productivity can be increased so as to achieve profitable production from wells without exceeding the acceptable stress levels in the rock.

To prevent water (or gas) influxes during multiphase flow, a horizontal well has two advantages. It can be drilled near the top of the reservoir so as to obtain as much clearance as possible. Likewise, even with greater total production, production per unit length is less, thus locally causing more moderate stress on the oil/water or oil/gas interface. The shape of this interface is thus smoother, and calculations show that vertical sweep is more efficient, and hence recovery is greater[5].

Generally speaking, in multiphase flow, horizontal wells reveal all the more superiority as the mobility ratio is unfavorable, e.g. heavy oil driven by water. The phenomenon to be prevented is indeed the breakthrough of fronts, which occurs all the sooner as flow is more unstable. The steadiness of drainage among horizontal wells provides more homogeneous progression to fronts, which is especially advantageous at the beginning of production. Nonetheless, since reservoirs are more or less heterogeneous, full benefit can be drawn from such favorable effects only if selective completions can be implemented in horizontal wells.

For partly similar reasons, horizontal wells are advantageous for thermal recovery[1]. The exact positioning of a perforated injection casing at a specific depth in a reservoir should enable steam to be fed in easily so that the zone it invades expands steadily, while decreasing heat losses into the surrounding formations.

To be able to compare costs with the use of conventional vertical wells, some thinking was devoted to the overall productivity on the scale of the field, simultaneously involving the geometry of production wells and their spacing[6]. This confirms that, in order to obtain the same production under equivalent conditions, use of horizontal wells enables the number of wells to be divided by a factor of about 4. From the theoretical standpoint, the savings can be greater for very thin production beds. However, under this assumption, it is not certain that it will be profitable to produce from such a thin bed.

The economic interest of horizontal wells clearly depends on control of their higher drilling and completion costs compared to those of vertical wells.

Drilling the four horizontal wells

The trajectories and the main data concerning the four horizontal wells appear on picture N° 1.

Horizontal wells Lacq 90 and Lacq 91, at a 600 m (2,000 ft) depth were drilled mainly to prove the overall feasability of horizontal drilling in a shallow well-known deposit, the upper Lacq field[7,8]. Directional drilling up to a 90° angle and drilling horizontal sections through the reservoir of 270 m (900 ft) and 370 m (1,210 ft) lengths served to define and check efficiency procedures as well as to test some of the most suitable bottom holeassemblies.

Instead of building the angle at a constant rate as previously planned, the actual profile of the Lacq 90 well appeared easier to follow and was preferred when drilling the Lacq 91 well. This type of profile, with two straight sections at 30° and 70° inclination angles was followed very closely at Lacq 91. It enables the friction occurring in the curved sections to be limited.

When drilling deeper, down to a 1,370 m (4,500 ft) vertical depth, on the offshore Italian Rospo Mare field, this type of profile was adjusted to cope with the expected configuration of the formations to be crossed through[9,10]. Indeed the influence of the heterogeneity of the formations drilled through is of capital importance and has to be considered with great care.

The fourth well, Casteralou 110, at a 2,900 m (9,600 ft) depth, gave the opportunity of better understanding and overcoming of the drilling problems and procedures.

The main concerns apply to the effects of gravity, the angle of which with the axis of the hole obviously grows up to 90°. Thus, to transmit weight on the bit, it is necessary to put the lower part of the string in compression. The drill collars are removed from the bottomhole assembly where they become useless. They are placed in the upper hole. The lower part of the string, now under compression, is made of heavyweight drill pipes.

Since [illegible]-line-operated instruments cannot be run in the hole as usual, unless they are pumped, surveying the well was at first a time consuming operation. Now, the M W D type tools available in the 6 3/4-in. size used in the 8 1/2-in. drilling phase save a lot of time.

Proper definition of the mud with good rheology and weight must meet many goals :

- efficient cleaning of the hole, especially around the critical 70° inclination angle area ;
- reducing sticking risks as much as possible ;
- limiting the dragging effect resulting from bending of the compressed part of the string and from friction in the build-up angle sections of the well.

Horizontal drilling is expensive, two to three times the cost of a nearby vertical well in the 1,000 m (3,000 ft) to 3,000 m (10,000 ft) vertical depth range. This is so mainly because, up to now, any correction of angle requires the drill string to be pulled out of the hole, to be modified. If most of the modifications can be made remote controlled from the surface, great time saving will result, and the cost should come close to being proportional to the overall length drilled.

Logging and coring horizontal wells

In carbonate reservoirs, logging as well as coring are very valuable instruments for determining the evolution of facies and fluid distribution.

New systems had to be developped to meet the characteristics of horizontal wells because logging tools are conventionally run into holes on a wireline. Among the systems developed for this purpose, the equipment called SIMPHOR[11,12] was designed with a noticeable emphasis on safety. At any time circulation of mud in the well is possible, so that it can always be kept under control.

The procedure with SIMPHOR is as follows. The logging tool and its protective housing are attached to the connector housing. The entire unit is then screwed onto the end of the first length of drill pipe and run down to the zone to be recorded by making up the drill string. When the area to be logged is reached, a lateral window sub is inserted in the drill string. A sinker bar with a 7 contact connector is attached to the logging wireline that goes through the lateral window. The sinker bar is pumped down the drill string with mud. Once at the bottom, the sinker bar is mechanically and electrically connected to the protective housing of the logging tool, opening downhole a bypass aimed at mud circulation. Logging is performed while adding new stands. After logging, the sinker bar is unlatched and pulled back up.

A large set of logs has been recorded in horizontal wells. Their analysis enriched by the study of the cores sampled with a good recovery ratio, gave a good representation of the Rospo Mare field (Fig. 2).

Completion of horizontal wells

Since the length of the production interval of a horizontal hole reaches 1,500 ft (500 m) or more, it usually intersects several facies. Although the horizontal wellbore remains at the same level, experience shows that it does not stay for sure in the same geologic stratum. For example, in the Rospo Mare field, the reservoir rock is massive dolomite crossed by fissures that intersect the big voids of the karstic system. In this highly heterogeneous medium, sandstone was encountered by the horizontal drainhole in many places (Fig. 2).

Considering the other three horizontal wells, they were drilled in fissured limestone. The density of fissuration in the rock matrix varies on a broad scale. Thus, the capability to make two or three distinct zones produce separately is needed to deliver a good production of oil for a long time, that means even after water breaks through. One might expect that the place where water will begin to flow into the well lies close to the bigger and wide expanding fissures. When no more oil should be produced in this area, the part of the drain hole concerned has to be shut off, and production must be continued in the remaining interval, eventually with a higher drawdown to keep the same production level.

As a matter of fact, the first three wells of the project were originally equipped the simplest way. A slotted liner was run in. This liner was designed to keep the entire length of the drainhole open by preventing any obstruction of the hole by collapse. Some rock mechanics study had previously been done to check that in all these particular reservoirs the narrow tunnel would be stable enough so as not to shut itself off during the drilling phase. As far as the production phase is concerned with its successive drawdown cycles, completion with a 7-in. slotted liner was considered to be reasonably safe.

Later, during the production phase described in the following chapters, the slotted liner appeared as a significant handicap every time a workover operation was necessary. The need to improve the productivity of the Lacq 90 well caused an acidizing job to be performed[13]. A very high water/oil ratio in the Lacq 91 well resulting from a wide crack allowing an easy path to water into the well made it necessary to program a work-over operation and to replace the slotted liner with a selective completion.

The Castéra Lou 110 well was immediately equipped with a selective completion (Fig. 3).

Production of the Lacq 90 well

The Upper Lacq oil field is a shallow chalky reservoir, partially depleted, where the water-oil transition zone almost reaches the top of the structure. The Lacq 90 horizontal well lies in the less fissured zone of the reservoir. It initially produced with a 2.67 m^3/d/bar (116 bbl/D/psi) productivity index. The initial oil cut was of 3 %, which is slightly better than the average of 2 % in this area.

Anyway, the poorer-than-expected productivity index caused an acidizing job to be performed.

The problem was to squeeze acid gently into the reservoir matrix through the walls of the well, spreading it as uniformly as possible throughout the production zone. The stumbling block to be avoided was that of setting up a preferential path in one of the biggest fractures and then allowing the entire treatment acid to flow into it. It is evident that the acid is, as usually, useful in the less permeable area that most needs to be stimulated. On the contrary the opening of a wide expanding fissure with a broader size may be very harmful by providing an easy channel to water. But, how can the acid be prevented from flowing parallel to the non-cemented liner in the annulus between it and the walls of the well, and from escaping through the walls at the most permeable area ?

The answer to this question which was found and implemented in the Lacq 90 well is sketched on Picture 4. The principle of the procedure is to squeeze small plugs of acid through the walls of the hole in several locations by pushing each of them by a plug of gel. Inside the well, the acid is replaced by a volume of sufficiently viscous fluid so as not to be moved during the subsequent steps of the operation. The gel is produced from guar gum, and small intermediate plugs of water are introduced in the sequence whenever it is necessary to protect the gel from mixing with the acid. The operation performed has allowed to meet to goal of increasing the productivity index by 80 %, and oil production was increased by 25 %.

Production of the Lacq 91 well

The Lacq 91 well lies mainly in the same chalky zone of the reservoir as Lacq 90, but for its middle part which lies in a very fissured dolomitic zone. During the drilling of the well, total losses occurred in this zone at a total drilled depth of 1,050 m (3,450 ft). A large fracture is clearly identified on V.D.L. sonic logs[4].

During the first year of production, the Lacq 91 well produced mainly water with a productivity index as high as 240 m^3/d/bar (10,000 bbl/D/psi). The fracture identified in the middle part was suspected to act as a path for the water entering the well. Thus it was decided to perform a workover operation to plug the fracture.

The 500 m (1,500 ft) long slotted liner was fished out because it would not have been possible to perform safely any job through its partially clogged slots. The crack was plugged with two tons of sand sealed with cement slurry. A composite completion was run so that the bottom end of the well alone was put into production for half a year. During this period the oil cut in this well was of 10 %, which is more than twice the one of the wells in the neighborhood.

Production of the Rospo Mare 6 well

The offshore Rospo Mare field lies in the Italian part of the Adriatic Sea. A subsidiary Company of the Elf Aquitaine Group is operator with AGIP as a partner.

The reservoir of Rospo Mare is made of big karstic voids interconnected through fractures. Since there is almost no producible oil in the tight dolomitic matrix, the goal of the production engineers was to draw as much oil as possible from the voids. The high viscosity (140 cp in the reservoir) of this 12° API gravity oil makes it difficult to avoid water production from the active aquifer that lies below.

So, to check the production feasibility of this field, a production pilot was put into production. It comprises three wells, one horizontal, one deviated (45°), and one vertical (Fig. 2). Since the horizontal well intersects several voids, its productivity index is very high. It has not been measured precisely yet. This well combines the two advantages over the other wells, of a smaller drawdown during production and of a higher position in the reservoir so as to obtain the greatest possible height above the W.O.C. Its productivity is more than 20 times greater than that of the other two wells. Its production easily reaches 480 m^3/d (3,000 bbl/D) waterfree, whereas the critical flows of the other two wells are 120 m^3/d (750 bbl/D) and 25 m^3/d (150 bbl/D).

Production of the Castéra Lou 110 well

The Castéra Lou field is a limestone edge-reservoir made of two layers with low permeability. The upper layer is chalk. The lower layer is dolomite.

The Castéra Lou 110 horizontal well was drilled at the top of the reservoir 80 m (270 ft) above the W.O.C. The main purpose of drilling this well was t prevent waterconing.

Total mud losses occurred during drilling near the bottom end of the horizontal well, when entering a very fractured area next to the fault sealing the reservoir. The fear that water coming through this fractured area might later invade the well in a similar way as in Lacq 91 induced to equip the Castéra Lou 110 well with the selective completion shown on Picture 3. The production zone is divided into two parts separated by newly designed formation packers. At least one of them has been properly inflated, but no clear evidence of the efficiency of the seal has been obtained yet.

Conclusion

Under industrial standards, good reliability has been attained in drilling, coring and logging of the four European horizontal wells spudded in fissured carbonate oil reservoirs. Comparing each of them with a nearby vertical well, its overall cost is around three times more.

Productivity index improvement, as compared to vertical wells, usually reaches four times, sometimes more than ten in highly heterogeneous reservoirs. Taking full advantage of the geometry of the reservoir, by implementing carefully the horizontal wells, helps to avoid or reduce fluid interface problems as shown in Rospo Mare. In E.O.R. processes, horizontal wells improve the recovery.

Thus, if horizontal wells are not to be applied anywhere, they might be of economic interest in the following reservoirs :

- thin formations,
- vertically fractured tight formations,
- formations with fluid interface problems,
- enhancement of oil or gas sweeping by a driving fluid,
- soft formations such as chalk.

Because attempts to master selective completion techniques have been only partially successful, a new research program on completion and production logging was launched early this year.

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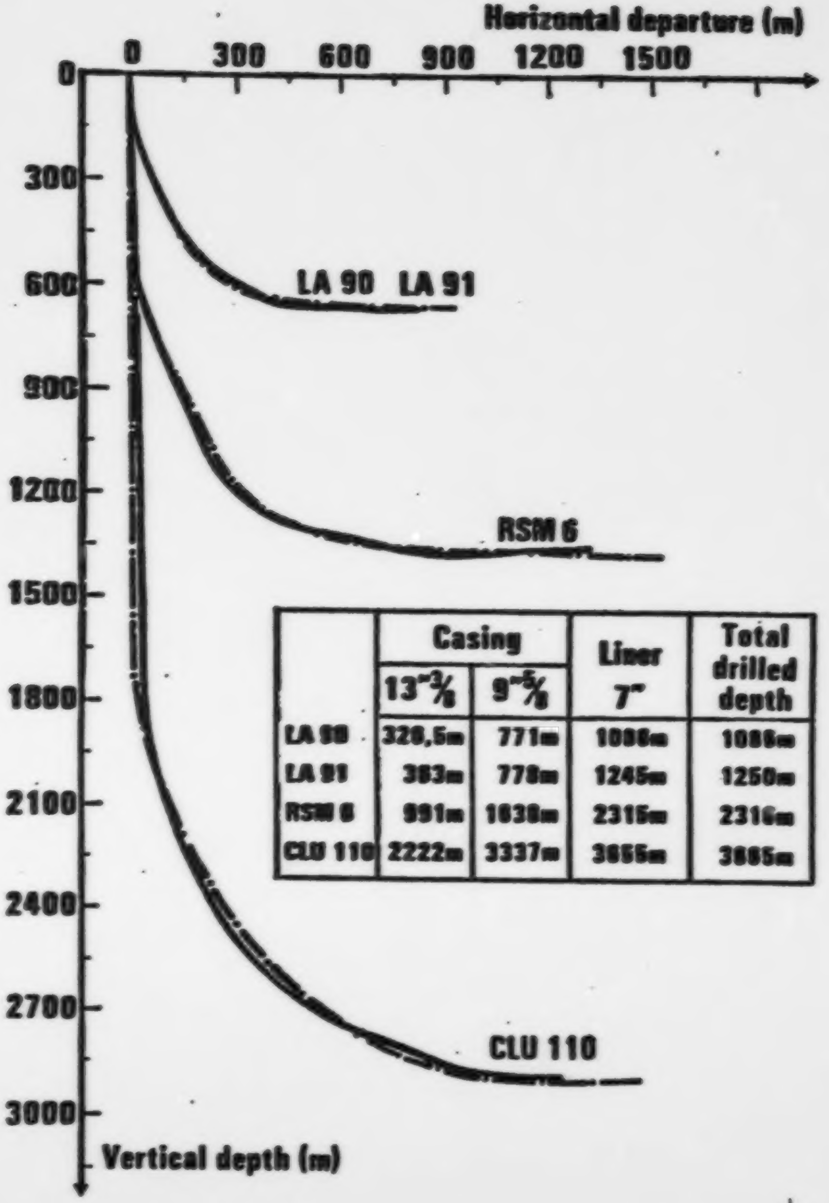


	Casing		Liner	Total drilled depth
	13"3/8	9"5/8	7"	
LA 90	328,5m	771m	1088m	1088m
LA 91	383m	778m	1245m	1250m
RSM 6	991m	1638m	2315m	2316m
CLU 110	2222m	3337m	3865m	3885m

FIGURE 1 : THE PROFILES OF THE FOUR HORIZONTAL WELLS

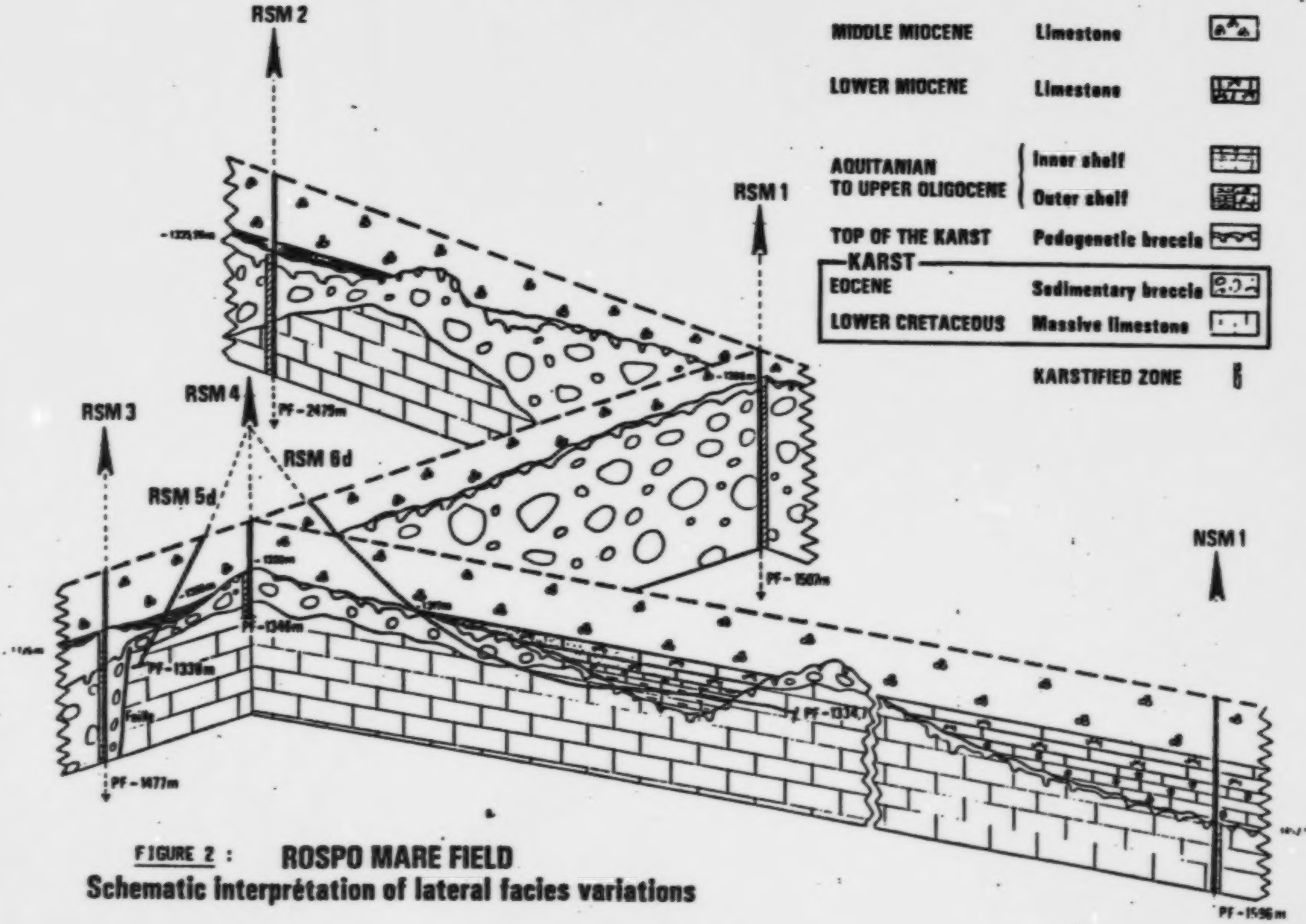


FIGURE 2 : ROSPO MARE FIELD
Schematic interprétation of lateral facies variations

FIGURE 3 : COMPLETION OF THE HORIZONTAL WELL CLU 110

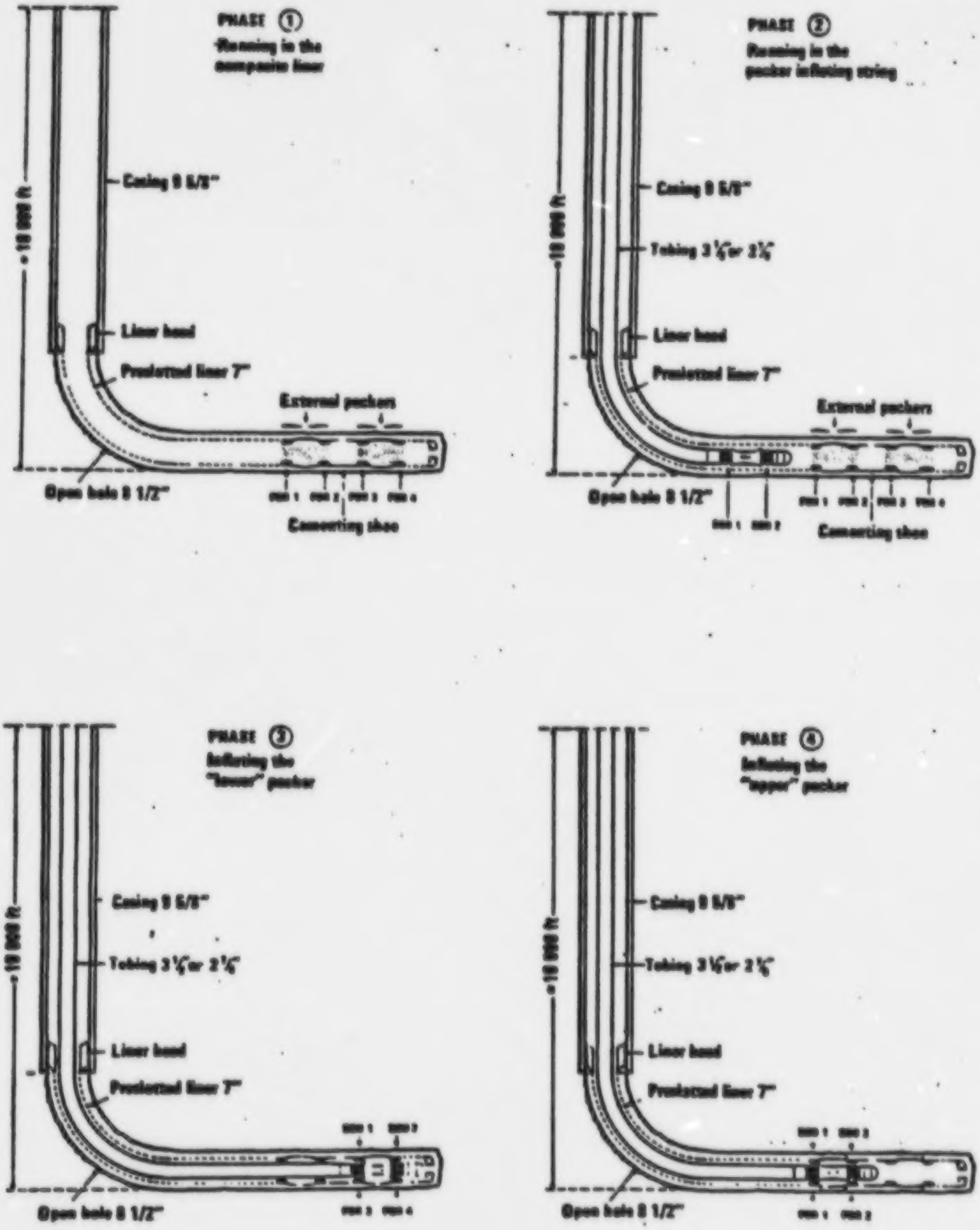
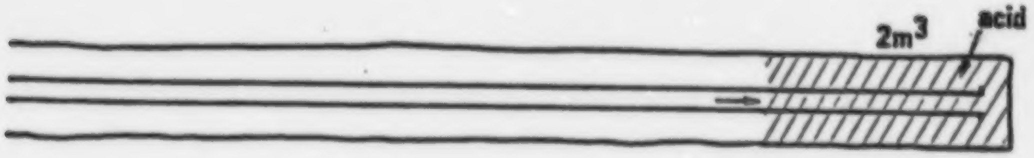
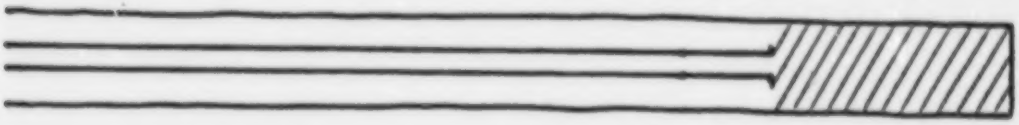


FIGURE 4 : ACIDIZATION ON LACQ 90

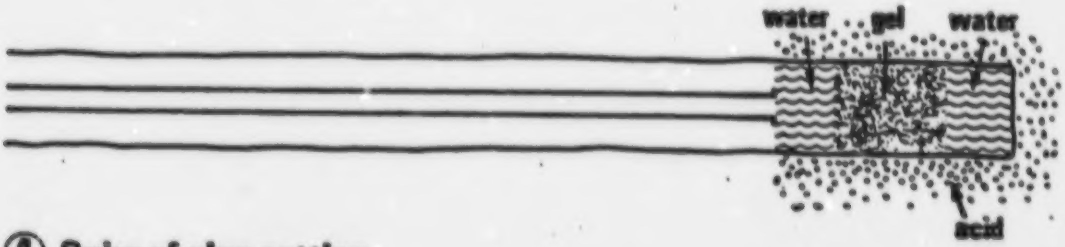
① Setting a first acid plug by circulating



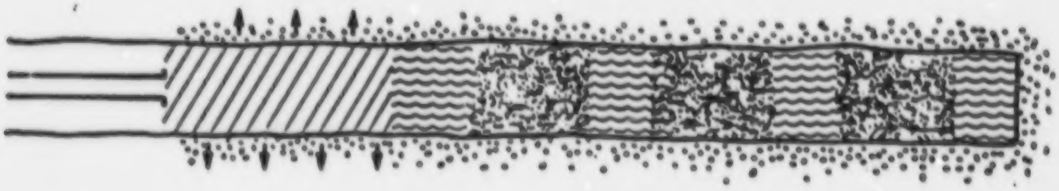
② Pulling out 80m. of drill string



③ Injection of a gel plug



④ Order of plug setting



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Horizontal Wells' Production After Five Years

by L.H. Reiss, *Elf Aquitaine*

SPE Member

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ABSTRACT

August 1980 : the first horizontal well (out of four) drilled by Elf Aquitaine during the last six years produced its first barrel of oil. The others followed between 1981 and 1983.

There is now enough production history to draw conclusions.

- Have horizontal wells crossed highly productive vertical fractures ? Yes. Sommetimes unexpectedly.
- Have horizontal wells increased reservoir sweep efficiency (and oil recovery) ? Yes. One well is still producing water-free after a cumulative production exceeding two millions barrels of oil, which is far beyond the possibilities of its vertical neighbours.
- Are the theoritical calculations of the productivity increase in accordance with actual field results ? Yes. Within the non fractured sections, the "horizontal" productivity lies between 2 and 4 times the "vertical" productivity.
- Are transient pressure test interpretations available ? Yes, including rules for designing tests procedures.
- Is it possible to make measurements inside horizontal wells ? Yes, since almost all available logs have been usefully recorded horizontally and two production logging attempts have been successfully made. Results : fracture location, oil and water entry points.
- What about production geology ? Surprising ... Some unexpected reservoir showed up : corrugated reservoir roof, buried valleys, fractured reservoir intrusion.
- It is possible to complete selectively these long (about 500 metres) horizontal wells ? Not yet, despite two attempts. All the wells are completed by use of preslotted non cimented liners.
- What is the main target of the research program ? This $ 2 millions efforts is mostly devoted at mastering selective completion of horizontal wells by use of horizontal casing cimentation and/or, external packers tests, and improved bottom hole diameter measuring devices.
- Any industrial project ? Yes. The Rospo Mare oil field (offshore Italy) will be developed by use of horizontal wells.

INTRODUCTION

Horizontal drilling is not a really new concept, since considerable efforts have been put during the fifties and sixties, mostly in the USSR, but at that time the results in terms of well production were rather disapointing.

Beginning at the end of the seventies, the today horizontal drilling attempt [1,2,3,4] of the oil industry is due to the combined effect of the improvement of directional drilling techniques and the pressure for new oil.

Its originality is to adapt horizontal wells to definite reservoir engineering targets - and the originality of the originality is that it lead at least in the Elf* attempt, to a prolific oil well[1].

The know - how that has been gained during the latter attempt (for horizontal wells drilled in Europe between 1979 and 1983), pertaining to drilling[1], coring[1] logging devices[5,6] as well as reservoir engineering[7,8] has been described in other papers.

However, very little has been published about the production behavior of these wells. Now, their production histories are long enough (2 to 5 years) to allow analyzing them.

But before this, it must be kept in mind that[1] : "Among the four horizontal wells, the two first ones, Lacq 90 and 91 were devoted to master the drilling, completing and measuring techniques. Production was of course haped for, but as a side result. The fourth well, Castéra Lou 110 had been desdigned to master deep drilling problems, as well as completion : a good production behaviour was hoped. Our third well, Rospo Mare 6 D industrially drilled by the Elf Italian Subsidiary and AGIP was strictly aimed at production purposes".

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*in association either with the IFP or with the AGIP

This "horizontal" production study is the main aim of the present paper.

PRODUCTION BEHAVIOUR OF THE WELLS

Let's look at the field reservoir engineering informations and the production records of the horizontal wells, having in mind they all are pumped and not selectively completed.

Lacq Superieur

The Lacq Supérieur oil field is located in S.W., France, on shore. The reservoir lies at a depth of 600 metres. The initial oil column amounted to 100 metres. Inside the area where the horizontal wells have been spudded, the rock porosity and permeability are about 20 % and 1 millidarcy, respectively. The oil viscosity is 17 centipoises.

This field has produced oil with an increasing water cut since 25 Years. It is almost swept since its average water cut amounts to 98 %.

Areally speaking, the reservoir is made up by two distinct but communicating formations, i.e. a highly fractured dolomite (PI = 100 Cum/day/athm) and limestone lenses, almost non fractured (PI = 1 cum/day/athm).

Lacq 90 horizontal well (see figure 5)

The production history of the well La 90 is displayed on fig. 5 , as well as the average of its vertical neighbours, including the dry wells located within the external boundary of the SW lens.

The daily oil production of La 90 is about 3 times larger than that of its typical vertical neighbour. This is consistent with the theoritical calculations, one can make using the formula n° 1 given later on.

A strong interference has been noticed by accident between La 90 and the best producer of its area, La 44, which suggests the existence of a permeable channel between them. La 90 might produce predominantly from this permeable section.

Lacq 91 (see fig. 6)

Lacq 91 has crossed successively chalk ("head"), dolomite, and chalk again ("tail"). The chalk was expected but not the highly fractured dolomite.

The productivity of these sections are about 1 cum/day/athm, 200 cum/day/athm, 1 cum/day/athm, respectively. As mentioned later on, an attempt for completing selectively this well has been made, which succeeded partially since the "head" had been satisfactorily cimented, and the fractured dolomite plugged, since it had appeared filled by water. This allowed for some time the "tail" to be produced, with the lowest water cut of the field... 90 %. Then, accidentally, the cimentation of the head as well as the plugging of the fracture were destroyed.

Today, the well is mainly producing from the fractured dolomite, since its PI is about 200 cum/day/athm with a 99 % water cut. This high productivity has allowed to produce La 91 through a centrifugal pump at very high production rate and small P. The daily oil production amounts to 15 cum/day which is the total oil production of this NE lens of the field. But the small P forbids the possibility of producting the poorly productive "head" and "tail" which need big P to display industrial rates.

Castera Lou (see fig. 7)

The Castera Lou oil field is located in S.W. France, on shore. The reservoir where the horizontal well CLU 110 was spudded is a poorly or non fractured dolomite, the "Breche de Garlin" - It lies 2.900 metres under the sea level and has a 70 metres thick oil column overlying a water bearing formation. It had been produced since 4 years through 3 vertical wells.

The rock porosity and permeability are of the order of 10 % and 0,5 millidarcys, respectively. The oil viscosity is 1.5 centipoises.

The horizontal well has crossed the reservoir over 330 metres, then complete mud losses, indicating the presence of open fractures, occured. They were subsequently plugged.

One can notice on the production records (figure 7) that the daily oil production of the horizontal well is about 5 times larger that of typical vertical neighbour. This is consistent with the calculations one can make using the formula given later on.

Despite a very high production drawdown (60 athmospheres), Clu 110 produced oil almost one year before the water broke through. At that time, the cumulative oil production was close to 10.000 tons.

There must exist some horizontal tight lens protecting the well against the vertical motion of the "water crest" (or "horizontal cone").

The present production of Clu 110 is felt to come from the non (a slightly) fractured portion of the reservoir. It is intended to continue producing the latter until it is completely flooded and then to try to unplug the fractures and produce some oil from them.

Rospo Mare

The Elf - IFP horizontal drilling research effort had been specifically designed in 1977 to master the challenge of producing the Rospo Mare off shore heavy oil reservoir which was considered at that time non economically producible by conventional means[1]. The reservoir is 1.200 metres deep. It is a karst, made up by caverns and voids intersected by vertical fractures. The rock by itself is tight. The oil in place volume might be about 200 millions cu metres.

The oil is heavy (11° API), its viscosity is 300 cp at reservoir conditions. The contrast in specific gravities between oil and water is only .01 grams per cucm which indicates a poor potential influence of the gravity forces.

Low gravity contrast, big mobility contrast, big vertical permeability, all the ingredients were met to be faced to severe interface problems, at least in the case of vertical wells. It has been thought that by drilling horizontally long drains as far as possible from the water oil contract, it would be possible to intersect many fractures and voids and consequently to increase drastically the productivity of the well. This in turn would allow to produce under a very limited P, leading to a gentle deformation of the water oil contact which is one of the keys for a satisfactory oil sweep efficiency.

Just after the two Lacq horizontal test wells had been drilled the ability to drill horizontally was considered as sufficient, and a horizontal well was included within a 3 wells production pilot. These three wells have been producing since the end of 1982. See their production records on figure 8. Some important features.

The 3 wells produce at their maximum water free (critical) rates.

These critical rates decline regularly. This is an indication of a continuous and regional uprise of the water oil contact and therefore a satisfactory oil sweep efficiency.

The horizontal well, RSM6, outclasses the 2 other wells on a productivity point of view (more than 20 times) as well as on critical rate values (7.4 times) or on a cumulative oil production basis (4.6 times). The sweep efficiencies comparison inside the area of the pilot can be estimated from the cumulative oil production of the wells : 4.6 times larger for the horizontal well than that of the average fo the others.

The flow sources along the wells are discontinuous, since the reservoir is a karst (caverns intersected by natural fractures scattered within a very tight almost impermeable rock). The uncertainty pertaining to the location of these sources avoided the analysis of the reservoir production behaviour, having in mind the further potential development of the Rospo Mare field by horizontal wells.

To overcome this difficulty, one attempt of production logging* was made at RSM6 in 1984 (after a first trial in Lacq 91), taking into account the discontinuous sources and the high viscou oil that could give a chance to record some significant flowing spots.

The main results are that the last half of the well (the "tail" does not display any productive behaviour, and that within the first half (the "head") there are 3 fluid entry sections. The most productive section is located close to the cavern that has been crossed while drilling the well. The distance between the flow sources (karstic voids, main fractures) is felt to be of the order of 100 metres. Therefore it is hoped that a localized stimulation of the tail could reach one of these sources and regenerate the well oil production capacity for some time at least.

And now, some conclusions from these observations.

HAVE HORIZONTAL WELLS INTERSECTED HIGHLY PRODUCTIVE VERTICAL FRACTURES ?

Yes. The 4 wells above described have all intersected vertical fractures. In one case, this is only suspected (Lacq 90). In two cases, this was a surprise (Lacq 91, Castera Lou 110). In Rospo Mare 6, this was the (random) target.

Intersecting vertical fractures by horizontal wells is not surprising, since according to the rock mechanics laws, the rock stresses prevailing within most hydrocarbon reservoirs result in vertical or highly inclined fractures.
This gives potential targets to horizontal wells.

HAVE HORIZONTAL WELLS INCREASED SWEEP EFFICIENCY (AND OIL RECOVERY) ?

Yes. Let's compare the production data of the 3 wells of the production pilot of Rospo Mare, since they have been put into production almost simultaneously.

As indicated previously the sweep efficiency of the horizontal well RSM6 is 4.6 times larger than the average of the others. This should be a minimum value since the oil daily production of the well RSM4 is only 25 cum/day which would not be economical if the well were producing under its own merits.

Castera Lou may also be considered.

Production forecasts have been made on this field on a well per well basis : the cumulative oil production of the horizontal well amounts to 2.5 times that one of the typical surrounding vertical well. This might be a minimum since the possibility of producing oil through the vertical fractures array of the "tail" has not been taken into account.

ARE THE THEORITICAL CALCULATIONS OF THE PRODUCTIVITY INCREASE IN ACCORDANCE WITH ACTUAL FIELD RESULTS ?

Yes. The following formula allows an easy comparison of the productivity increase of horizontal wells as compared to vertical ones :

$$\frac{PI_H}{PI_V} = \frac{\ln\left(\frac{r_{ev}}{r_{wv}}\right)}{\ln \dfrac{1 + \sqrt{1 - \left(\frac{L}{2r_{eH}}\right)^2}}{\frac{L}{2r_{eH}}} + \frac{h}{L} \ln\left(\frac{h}{2\, r_{wH}}\right)} \quad (1)$$

This formula can be extended to anisotropie reservoirs, stratified reservoirs, the stratification being converted into anisotropy as indicated by Dupuy9. The formula can also be used for naturally vertically fractured reservoirs by multiplying the second member by kf/km and replacing r_{ev} by a r_{ev} kf is generally known from well tests 10. Also, when the vertical well is partially penetrating the formation, replace h by hxRe-Re is a factor giving the productivity reduction of a well when its penetra tion is decreased $\frac{hp}{h} = 1$ to $\frac{hp}{h} < 1$.

---

* RSM6 has been given a 2 tubings completion for the sake of production through one tubing, measurement using the second one with a pumped out technique.

Two sets of calculations have been made, one for the non highly fractured sections (Lacq 90, Castera Lou 110), and the other for the fractured sections.

This displays reasonnable agrement with the field measured productivity, i.e., productivity improvement of about 3 for now fractured formation, and (about) ten or hundred for highly fractured formations provided these fractures are not intersected by the vertical well.

This should not shadow the fact that, up to now, the flow distribution along horizontal wells is almost unknown, and supposed continuously distributed along it for the sake of calculation.

ARE TRANSIENT PRESSURE TEST INTERPRETATION AVAILABLF

Yes. This point is described within an other paper[9], the aim of which is :

"To fullfilling the need for designing and interpreting well test in horizontal wells.

The analytical solutions for the following problems are developped :

- infinite or limited reservoirs with impermeable or constant pressure boundaries.
- horizontal well with wellbore storage and skin.
- Horizontal well with uniform flux or infinite conductivity.

A two-fold phenomenon, specific to horizontal wells, is pointed out on the pressure charts : the early time pressure evolution is due to a circular radial flow in a vertical plane perpendicular to the well and the late time pressure behaviour corresponds to an horizontal pseudo-radial flow.

For pratical uses a well test design and interpretation method are described which consists in :

- a semi-log analysis that provides the value of a pseudo-skin we have defined.
- a log-log analysis (with type curves drawn by a desktop computer).

Time criteria are also provided, to determine in particular the beginning of the pseudo-radial flow period."

Thus, some specific "horizontal" features of transient flow have been demonstrated.

But there is an another horizontal well characteristic : along their 1/3 or 1/2 mile length, the heterogeneity might be enormous. The interpretation tool described by Daviau and al, which fits a gap, is based on the assumption of reservoir homogeneity, and will fit the geological reality all the more the operators will be able to complete selectively their horizontal wells, which is not the case yet.

IS IT POSSIBLE TO MAKE MEASUREMENTS INSIDE HORIZONTAL WELLS ?

Yes. This pertains to well logging.

Chronologically, the following logs have been recorded on the four wells of the Elf program.

In Lacq 90, a Gamma Ray, inside the drill pipe

In Lacq 91, Gamma Ray, Induction, Sonic, VDL.

In Rospo Mare 6 : Borehole Compensated Induction Sonic (BHL-ISF), Variable Density Log (VDL), Gamma Ray (GR), Borehole Geometry Tool (BGT), Dual Laterolog (DLL).

A density Neutron Gamma Ray log was also recorded using small diameter tools pumped through the drillpipes run in the uncased zone.

In Castela Lou 110 : MWD (Measurement While Drilling) Gamma Ray.

One can notice a progression from Lacq to Rospo, then a fall at Castera Lou. The latter point has been caused by fluid control problems during the drilling phase of the reservoir

Two open hole logging techniques have been used, i.e.

. The SIMPHOR with large diameter logging tools screwed at the outlet of the drill pipes, the electrical cable hanging outside in the vertical portion of the well, then entering into the pipe through a side entry sub and finally pumped through the pipe and endly clamped to the logging tool.

. The pumped out technique, already used in highly deviated wells and extended to horizontal wells.

These logs are, regardless of the used procedure, are of excellent quality and reproductible. They have been usefull to show up some important heterogeneities, such as the highly fractured zone in Lacq 91 or buried valleys in Rospo Mare 6 (figure 4).

What is missing today is an occurate caliper with at least 4 independant arms, that could measure the shape of the cross sections of the hole along the well. This information is felt as necessary to implement the selective completion task.

An other important gap is the knowledge of the flow capacity of the different sections of the reservoir crossed laterally by the well. The thermometer might be a convenient solution for this. About production logging, two jobs have been successfully carried out as mentionned earlier. On a technological point of view, they have shown that the pumped out technique working over distances as large as 500 metres and carrying sophisticated tools, is feasible for production logging purposes.

Today, on can say that logging in horizontal wells is possible, relatively expensive (time consuming). The expected improvements, as far as the results are concerned, are related to the selection of the productive sections and the measurement of the out-of-roundness of the cross sections of the holes of the hole.

WHAT ABOUT PRODUCTION GEOLOGY ?

Four wells, four geological surprises.

Lacq 90 (see figure 1). With its close spacing* and its 25 years production history, the Lacq Superior field was supposed to be well known. It happened that the well had to be stopped because a core showed that it had crossed the roof of the reservoir and got outsite... a complete surprise.

* Due to the wells drilled not only for the shallow oil reservoir purpose but also for the deep gas reservoir aim.

Lacq 91 (see figure 2). The well intersected a non expected highly fractured section, which might indicate that the boundary between chalk and dolomite is not known.

Rospo Mare 6 (see figure 4). None of the 6 previously drilled wells on the Rospo Mare structure were able to intersect big enough caverns or fractures there are necessary to allow the expected high productivity, low production drawdown.
And the seventh well, the horizontal dit it !

Also this well give important geological informations such as the presence of clay filled buried valleys at the top of the reservoir to say nothing about the logic of the karstic system within this area, and mainly the location and size of the karstic caverns, as well as the possible impermeable layers that could protect the horizontal wells aginst the up coming water.

These informations, together with the results of a recent seismic survey will help to locate adequately the next horizontal wells of the Rospo Mare field.

Castera Lou (see figure 3). The roof of the reservoir in the area of the horizontal well displayed no significant differences with the initial predictions. However, two interesting informations were gathered from this well, that improved the geological knowledge of the reservoir.

Firstly, the exact location of a fault that is associated to the highly fractured section of the "tail" of the well, where occured the mud losses, and secondly the presence of a possible impermeable layer that prevented during one year the underlying water to break through at the well bore.

It is felt that improving the lateral facies knowledge of the reservoirs might be a potential for horizontal drilling, since it is possible to record any kind of well logs and also to drill horizontally up to 1 000 metres[2].

IT IS POSSIBLE TO COMPLETE SELECTIVELY THESE LONG (ABOUT 500 METRES, OR MORE) HORIZONTAL WELLS ?

Not yet.

Since the beginning of this effort, it had been recognized that drilling half a kilometre long (or more) within the reservoirs would lead to the necessity of keeping control of the different productive sections encountered.

In spite of this, the first test well, Lacq 90, was completed without any selective possibility, using the only industrially available equipment for horizontal wells, at the time, i.e. a pre slotted non cimented liner. The well could have been left open hole within the reservoir but the decision was taken to set a liner in order to prevent the hole to be plugged by a possible collapse of the reservoir rock.

But as early as 1981, in the second test well, Lacq 91, a sophisticated selective completion attempt was made, in order to take into account the presence of a chalky "head", a highly fissured centre and a chalky "tail".

The idea was to isolate the fractured section with two external packers, to cement and perforate the "head", and let the "tail" produce through a non cimented pre-slotted liner.

So the three potential horizontal well completions principes were to be tested, namely external packers, cementation and non cemented liners.

It happened that the external packers did not work since one of them could not be inflated and the second one proved non sealing. The horizontal cementation job of the "head" was apparently a success since a cimentation log showed many satisfactorily bounded intervals. The "head" has then been perforated horizontally over 20 metres. This was eased by the SIMPHOR apparatus. Unfortunatly, the cementation was destroyed by a further acid job.

Actually, the well is producing almost entirely from the highly fractured section through a non cemented partially perforated liner.

Rospo Mare 6, drilled in 1982, was an industrial well, and consequently had to be completed by feasible equipments, preslotted non cemented liner, in fact. Had a selective completion technique been available at that time, it would not have been necessary to run a relatively expensive production logging job to try to know where the outflows were comming from[2].

Castera Lou drilled in 1983, was an adequate candidate for the next selective completion attempt since it was a test well and has a horizontal section made up by 300 metres without significant fracture followed by 30 metres highly fractured. Two external packers were set at the boundary between the two zones. They were inflated satisfactorily but proved leaking during the subsequent pressure test. And the CLU 110 horizontal is producing through a non cemented liner, like the 3 other wells of the Elf program.

So, cementing casings horizontally is possible, although fragile. Isolating different sections within a horizontal well by use of external packers has proven unsuccessfull, up to now. In order to improve both procedures, the key point is the knowledge of the shape of the hole. One can assume that the latter might be ovalized by two factors : the rock stresses and the mechanical abrasion of the hole by the drilling pipe along the bottom bottom generatrix of the horizontal section of the well.

WHAT IS THE MAIN TARGET OF THE RESEARCH PROGRAM ?

Today, it seems that drilling, coring, logging horizontally can be reasonnably mastered, at least in some specific cases. Evaluating, even forecasting the performances of the wells, also[1].

The main remaining unknown is felt to be the selective completion of the long horizontal wells, according to the generally expected heterogeneity of the reservoirs.

ELF and IFP have therefore decided to continue their scientific research effort mostly devoted to mastering the selective completion of horizontal wells.

The budget allowed to the so called "PRODHOR" project is $ 2 millions, covering a two years period.

The most important part of this effort has been devoted to research and development of cementation techniques for horizontal well bores. These techniques are tested on models which reproduce as closely as possible the well conditions. They will lead to detailed recommandations and procedures for cementing horizontal wells.

The other parts are dedicated to :

- theoritical study of water or gas cresting (the "horizontal" coning,
- measuring techniques of bottom hole geometry (as mentionned earlier the knowledge of well bore cross-section shape is essential) and of bottom hole production parameters.
- evaluations of external casing packers performances in sealing ovalized holes,
- adjustment of production string equipment to horizontal wells according to selective production design requirements.

Research program results will be field tested at the earliest opportunity which means that the next horizontal test well (still to be decided) should have a fair chance to selectively completed.

ANY INDUSTRIAL PROJECT ?

Yes. This set of results, among them the most important being the excellent production behaviour of the Rospo Mare 6 horizontal well, has lead to the decision of developping the Rospo Mare field by horizontal wells.

The development project takes into account the geological uncertainty of the field and is therefore a step-by-step approach, i.e.

Detailed seismic job, vertical appraisal wells, 4 or 8 horizontal wells from an especially built plateform, 3 horizontal wells from the existing platform of the pilot. Then a more complete development of the Rospo Mare field by horizontal wells might be decided.

The beginning of the oil production is planned to 1987. Other candidates are under study.

CONCLUSION

As a conclusion, the author would like to draw the attention of the reader to some points that seem to him crucial. Succeeding in drilling horizontal wells means overcoming the overcost by the overproduction.

Reaching this target means selecting adequately the potential candidates, improving the "horizontal" production, and cutting down the overcost*.

Selecting adequately the candidates is the key point. This must be done thoroughly. It seems that the best fields of application for horizontal drilling might be reservoirs with scarcely spaced vertical permeable heterogeneities (fractures, karsts) tight gas with some fractures, and also severe water oil or gas oil interface deformation.

Improving "horizontal" production depends on the lateral heterogeneity. One has to measure it adequately and then to take benefit of it by the selective completion of horizontal wells.

ACKNOWLEDGEMENTS

The author is gratefull to all those who have contributed to this vast team job, espacially to H. Soudet for his work pertaining to the karst, and also to the management of Elf for permission to publish this paper.

NOMENCLATURE

a : average distance between two vertical fractures
h : thickness
k : permeability
L : length of a horizontal well within the reservoir
PI : productivity index

SUBSCRIPTS

e : external
f : fissure
H : horizontal
m : matrix (rock)
p : perforated
v : vertical
W : well

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* cutting down the overcost is not under the scope of this paper.

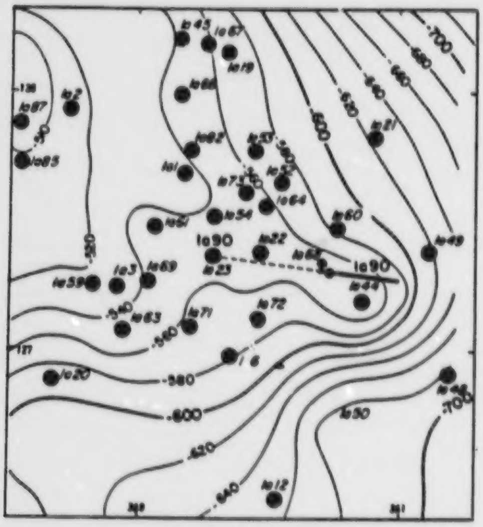

Fig. 1—The Lacq 90 horizontal well in its context (southeast part of the field).

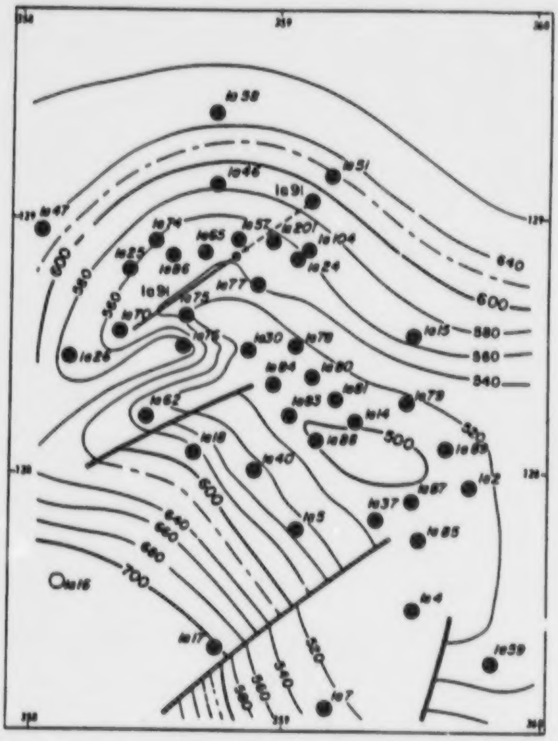

Fig. 2—The Lacq 91 horizontal well in its context (northeast part of the field).

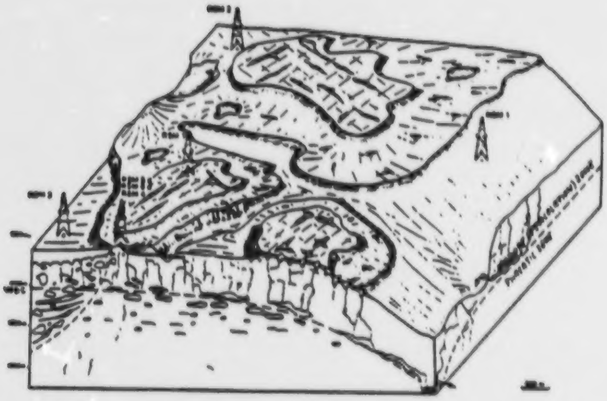

Fig. 3—A schematic view of the Rospo Mare karstic reservoir. Note the buried valley that has been crossed by the horizontal well Rospo Mare 6.

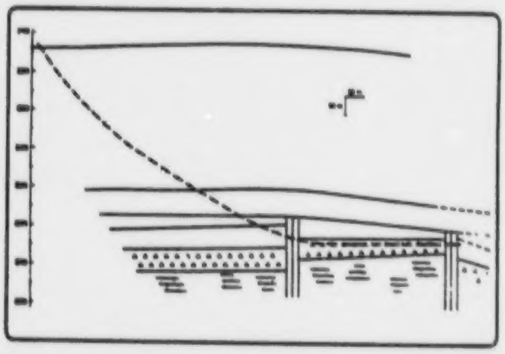

Fig. 4—A cross section of the reservoirs encountered by the Castera Lou 110 horizontal well

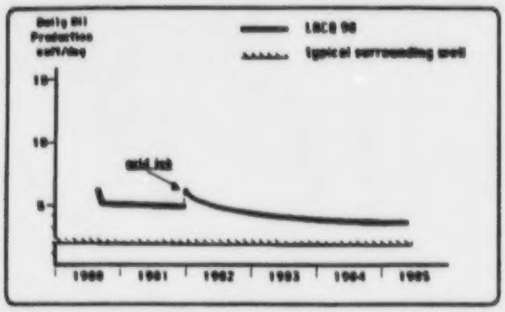

Fig. 5—Lacq 90 production profile. The initial rapid decline likely is due to a partial pore collapse—water cut = 50%.

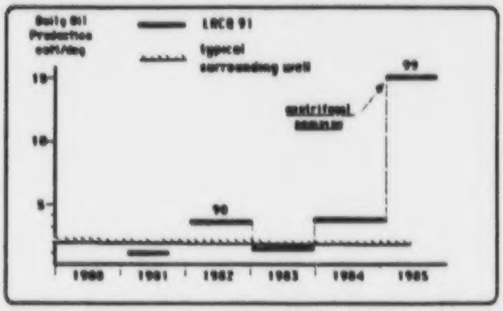

Fig. 6—Lacq 91 production profile. The erratic production behavior of this well reflects the numerous attempts made to master completion problems. The numbers above the curves indicate the water cut.

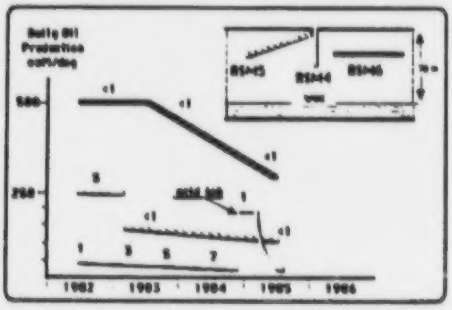

Fig. 7—Rospo Mare production pilot profiles. When possible the production rates are adjusted to the critical value (no water). The general decline of the critical rates reflects the regional uprise of the water/oil contact. The acid job performed on RSA44 may have reached a contiguous karstic cavern. The numbers above the curves indicate the water cut.

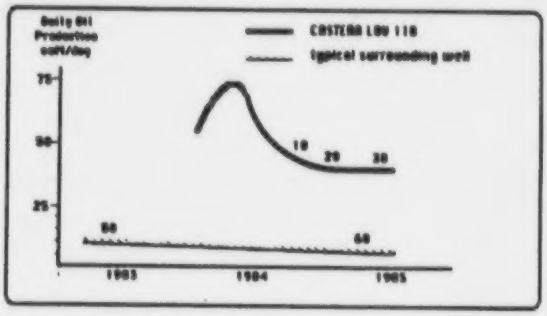

Fig. 8—Castera Lou production profile. The PI of this well is about 0.5 cum/day/bars (0.23 BOPD/psi). The production drawdown has reached 150 bars. The well has produced water-free during 1 year. The numbers above the curves indicate the water cut.

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MINING TECHNOLOGY ASSISTS OIL RECOVERY FROM WYOMING FIELD

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INTRODUCTION

An unusual oil recovery project in Wyoming combines aspects of mining and petroleum engineering technologies to increase production from the North Tisdale Field. The project basically consists of a horizontal tunnel, or adit in mining terminology, conventionally mined into a hillside (Fig. 1). The adit provides access to the oil sand from which an array of horizontal drainholes were drilled to varying lengths. At the present time it is the only project known to exist in the U.S. which produces oil using this method.

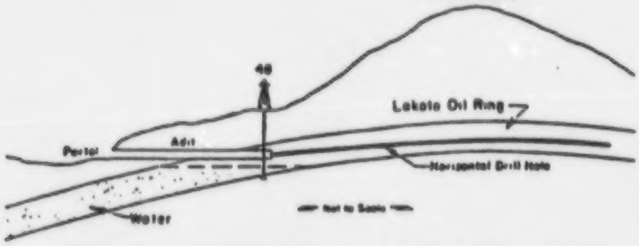

Fig. 1 - Generalized Conception of Project.

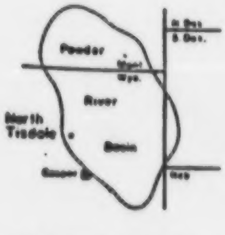

Fig. 2 - North Tisdale Location Map.

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Interstate Oil Compact Comm. Comm. Bull, VXXIII, N:, June 1981

HISTORY

Utilizing mining methods to produce petroleum from shallow deposits is not a new concept. Mining, in one form or another, has been used to recover various forms of petroleum for centuries. Its importance, however, has been overshadowed by conventional oil well development since Colonel Drake successfully drilled for oil in 1859. Petroleum mining can be traced back in history to before 5000 B.C. when deposits were mined in the Sinai Peninsula, Persia, and in the Euphrates River Valley. Ancient Egyptians used mined petroleum for embalming, and sailors have long known the value of tar mined from pits for making their vessels watertight. In more recent history, petroleum mining has been attempted in the United States with varying degrees of success. Projects have been attempted in Pennsylvania, Ohio, California, Texas, Kansas, Utah, and now Wyoming. It was employed in the late 1800's primarily as an alternative to conventional oil well drilling and later as a means of recovering additional reserves from shallow, pressure-depleted reservoirs. In addition to the early American oil mining attempts, two famous mining operations were successfully developed in the Pechelbronn Field in France and in the Wietze Field in Germany from 1917 to 1930. These mines were developed during a period of European history when oil was a commodity which was required almost regardless of the cost. In general, however, the petroleum industry has turned away from oil mining as a viable recovery method because of the more favorable economic factors associated with conventional drilling development. Recent developments in world oil supplies and prices are now providing producers with incentives to experiment with mining as an oil recovery technique.

Lakota Development

The North Tisdale Oil Field is located in the Powder River Basin approximately 70 miles (112.6 km) north of Casper, Wyoming. (Fig. 2) Production was first discovered in the field in 1952 from the Curtis Sandstone at a depth of 1000 ft (304.8 m). The discovery well had oil shows in the shallower Lakota Sand and the following year the first productive Lakota well was drilled. It was completed for 24 BOPD (3.8 m^3/d) and 2 BWPD (0.3 m^3/d) from a zone at 210 ft (64.0 m). Prior to this discovery, the Lakota was known to be oil productive in the area. Local history relates tales of early homesteaders and travellers who used oil obtained from seeps to lubricate wagon wheels.

The Lakota has provided a special challenge since development began in 1953. Production from early wells indicated that the reservoir initially produced through a weak gas drive which was replaced by gravity drainage shortly after completion. Local outcrops have allowed gas to escape and deplete the Lakota reservoir pressure. Typical of gravity drainage, conventional oil wells exhibit low initial producing rates and long producing lives. Lakota development was slow due to the marginal economics of the low volume wells. A total of six producing wells were drilled from 1953 to 1962 which had average initial producing rates of 8 BOPD (1.3 m^3/d) and 3 BWPD (0.5 m^3/d) (Fig. 3). Engineers recognized the fact that less than 2% of the oil in place would be recovered from the Lakota by primary methods. As a result, a one injection well pilot waterflood was tested in 1961 to investigate the feasibility of waterflooding the Lakota. The injection well produced a slight response in an offsetting producer. The one well project was expanded to a single five spot pattern to test the application of a fieldwide flood. The project was installed in 1962 and was discon-

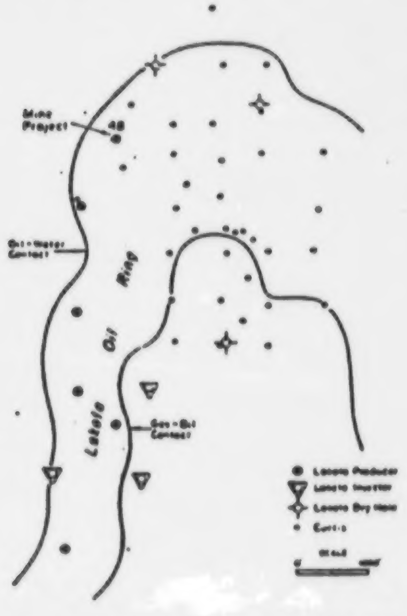

Fig. 3 - North Tisdale Producing Wells.

tinued after a significant volume of water was injected and no production or pressure response was noted in the central producing well or in offset producers. Lakota development halted after the pilot waterfloods due to a lack of success and poor economics. By 1972, all but three of the Lakota wells in the field were plugged, and of these only one continued to produce at a rate of 1.5 BOPD (0.2 m^3/d) and 1 BWPD (0.2 m^3/d). Total conventional recovery from the reservoir since discovery has been only 79,500 STBO (12,640 m^3).

Reservoir Characteristics

The North Tisdale Field is located structurally on the asymmetric, north plunging nose of the large Tisdale Mountain anticline. The steeper western limb of the anticline dips at 10 to 12 degrees, and the eastern limb dips at approximately 4 degrees. The Lakota structure generally parallels the surface topography of the mountain. The Lakota reservoir consists of a large gas cap surrounded by an oil ring which is further defined by a water-oil contact. The vertical depth reaches a maximum of 500 ft (152.4 m) on the crest and ridges of the mountain and decreases in depth in the eroded draws. A number of outcrops are evident in the most severely eroded draws. The average depth of the Lakota is approximately 300 ft (91.4 m) across the field.

The Lakota Sandstone consists primarily of a thin, tight Upper Sand interval and a thicker, oil productive Middle Sand section separated by a thin shaley zone. A water saturated Lower Sand is also apparent in some areas of the field. The Upper Sand averages 12 ft (3.6 m) in gross thickness and is generally described as a light grey, well cemented, medium-to-fine grained sandstone with spotty oil saturation. The Middle Lakota averages 40 ft (12.2 m) in gross thickness and consists of a light grey to tan, medium-grained calcareous sandstone. Well data indicate that the total gross Lakota thickness varies from 30 ft (9.1 m) to 100 ft (30.5 m) with an average thickness of 58 ft (17.7 m). Geological interpretations indicate that the thickness variations and the occasional absence of the Lower Sand are a result of channelling into the underlying Morrison Formation.

The Middle Lakota Sandstone exhibits reservoir rock and fluid properties that make it a good candidate for gravity drainage development. Gravity flow rates are dependent primarily on permeability, oil viscosity, and formation dip. The sand has an average porosity of 18.9% and a horizontal permeability to air ranging from 45 to 3000 md. Saturation determinations from log and core data indicate water saturations in the range of 40-50%. Net pay averages 21 ft (6.4 m) of sand with porosity greater than 10%. The 28° API gravity Lakota crude has a viscosity of 19 cp. at 70° F. (21.1° C.) and a pour point of -10° F. (23.3° C.). Average reservoir temperature is estimated to be 60° F. (15.6° C.). Utilizing the above data, a value of 733 bbl/ac-ft (4116 m^3 oil/m^3) of original oil in place has been estimated.

Planning and Design

In the mid-1970's, rising oil prices renewed an interest in the Lakota, which had remained essentially undeveloped at North Tisdale since 1962. In order to recover additional amounts of "known" Lakota oil, a project was begun to experiment with mining techniques to gain access to the sandstone and drill long horizontal drainholes into the reservoir. A much larger surface area would be created by a horizontal drainhole, and a higher oil production rate would be obtained than was possible with a conventional vertical wellbore. Two alternatives were investigated as possibilities for gaining access to the Lakota reservoir: 1) Drive a horizontal adit into the side of the mountain or, 2) sink a vertical shaft. Geological and mining personnel were consulted to aid in selecting the best approach. Personnel requirements, training requirements, specialized mining equipment, cost, and other factors were considered to determine that a horizontal adit would be the most feasible first choice.

Geologists and engineers selected the project site by combining topographic, geologic, and reservoir information. The site was located near the oil-water contact to maximize oil recovery by gravity drainage. Several mining, environmental, and drilling permits were applied for and obtained from various state and federal agencies after the mine site was chosen. Well No. 48 was drilled in May, 1977, to verify the presence of oil saturated reservoir rock and confirm the mine site. Well No. 48 also provided information on the depth of the oil-water contact and indicated the angle of decline which the horizontal adit would require to intersect the Lakota Sand. Well logs and drill cuttings indicated the Lakota top at 143 ft (43.6 m) and the top of the Middle Lakota Sand at 162 ft (49.4 m). Approximately 25 ft (7.6 m) of oil saturated reservoir was evident. It was determined that this section of the Middle Lakota in Well No. 48 would be the target point for the adit.

Mining Phase

In June, 1977, portal construction for the adit was completed. A steel security door was installed and the actual mining activity was initiated. Mining was accomplished with conventional drilling, blasting, and mucking equipment by a local Wyoming contractor. Mining of a 9 ft (2.7 m) wide by 8 ft (2.4 m) high adit proceeded by drilling 1 in. (2.5 cm) diameter holes, 5 ft (1.5 m) in length with a pneumatic drill. Several of these holes were drilled into the advancing face of the adit and packed with explosive charges. The charges were detonated from outside the adit. Specialized mining front end loaders then cleaned (or "mucked") out the rock debris. The initial 550 ft (167.6 m) of the adit was driven through weathered sections of the Fuson Shale. The instability of these shales required the use of conventional timber supports. Ground movement associated with small faults and swelling of the bentonitic clays in the shales during seasonal wet periods required the installation of steel beams in place of timber for adequate support. At a length of 720 ft (219.5 m) the adit was well within the competent Upper Lakota Sand, and ground control methods were changed from timbering to roof bolting. "Split Set" roof bolts were utilized consisting of a 5 ft (1.5 m) hollow steel tube, 1-1/2 in. (3.8 cm) in diameter hole with an open gap along the entire length. The bolts are driven into a 1-3/8 in. (3.5 cm) diameter hole with an air hammer. The friction between the tube and the wall of the hole provides resistance to movement of the ground.

A standard chain link fencing was slipped over the rock bolts and pinned to the roof and walls as protection against sloughing and spalling rock. This type of support was continued until the mining was halted at a length of 985 ft (300.2 m) where the wellbore of No. 48 was intersected. (Fig. 4.)

Ventilation of the adit was accomplished during mining by blowing air down the length of the adit through 18 in. (45.7 cm) flexible tubing to the face. Prior to the adit completion, a more permanent ventilation system was installed. A 22 in. (55.9 cm) hole was drilled to a depth of 176 ft (53.6 m) from the Well No. 48 surface location and cased to 18 in. (45.7 cm). The adit was then advanced to intersect the ventilation shaft and a 30 horsepower (22.4 kW) vane axial reversible fan was installed on the surface. The flexible ventilation tubing utilized during construction was removed, and ventilation is now accomplished by drawing fresh air in the portal, down the length of the adit, up the vent shaft, and through the fan. It is critical for a safe mining operation to maintain an adequate fresh air flow through the mine. The ventilation system meets all requirements set forth by state and federal gassy mine regulations.

The vent shaft also doubles as an emergency escape route. An escape hoist and cage is installed on the surface which can be lowered into the mine to remove personnel in the event of an underground emergency. The hoist is powered by an electric motor and is also equipped with a back-up generator. The unit was installed and approved in accordance with state and federal Mine Safety Regulations. These regulations require at least one qualified person on the surface at all times when personnel are underground.

At this point final preparations were made to begin the horizontal drilling phase of the project. A steel production sump tank was bolted into the floor directly below Well No. 48 to serve as a collection point for produced fluids. A conventional beam pumping unit was installed on the surface and tubing, rods, and pump were run down to the sump. (See Fig. 5.)

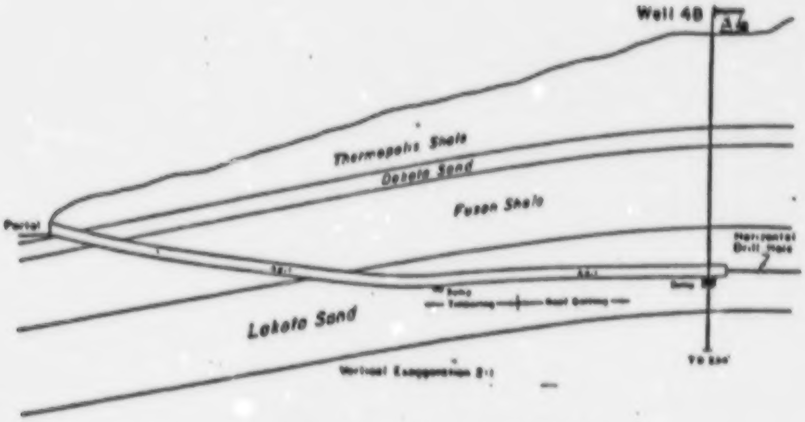

Fig. 4 - Actual Adit Cross-Section.

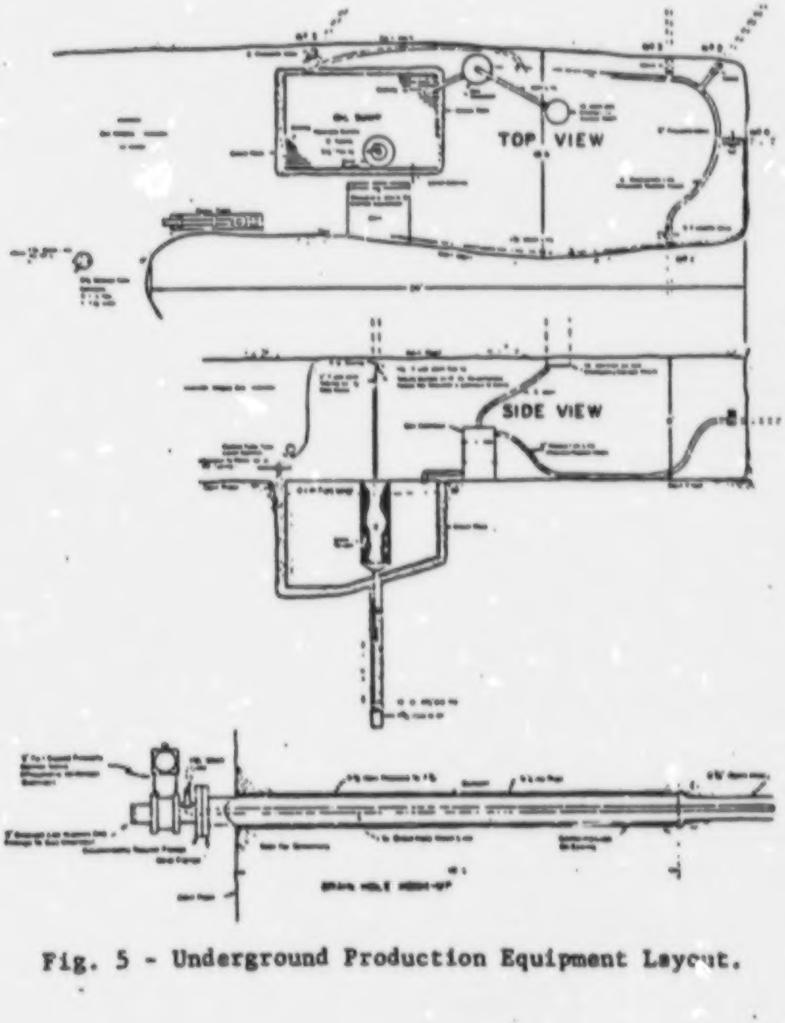

Fig. 5 - Underground Production Equipment Layout.

Drilling Phase

Specialized drilling equipment was used to drill the horizontal drainholes. The machinery had to meet several requirements: 1) The drill had to be compact and easily operated in the confined area; 2) it had to be safe for operation in a gassy atmosphere; and 3) it had to be easily controlled to correct for hole deviation. Deviation control was considered very important since it was desired to remain as close to the bottom of the oil saturated sand section as possible. This would take full advantage of the oil column height and result in maximum recoverable reserves. The drilling equipment used at North Tisdale was developed by Conoco Mining Research for coal seam degasification in underground mines. The compact drill utilized 5 ft (1.5 m) long joints of 2-1/4 in. (5.7 cm) drill pipe to drill a 2-7/8 in. (7.3 cm) diameter hole. The equipment was capable of drilling a hole 2000 ft (609.6 m) in length. The unit was operated totally by hydraulics and controlled by a portable valve control panel located underground. An electrically driven hydraulic power pack was located on the surface, and hydraulic lines were run down a separate 5-1/2 in. (14.0 cm) service hole drilled into the adit. Once the drilling equipment was oriented and secured in position, a 10 ft (3.0 m) long, 7-7/8 in. (20.0 cm) diameter hole was drilled into the wall. In this hole a length of 5-1/2 in. (14.0 cm) line pipe was cemented to serve as conductor pipe during drilling and also to provide a means of controlling flow from the completed drainhole. The remaining length of each hole was left open to the sand. Six horizontal drainholes were drilled. (See Fig. 6.) The holes and corresponding lengths are as follows:

#1	1498 ft (456.6 m)	#4	1700 ft (518.2 m)
#2	248 ft (75.6 m)	#5	970 ft (295.7 m)
#3	420 ft (128.0 m)	#6	1070 ft (326.1 m)

Holes No. 2, No. 3, and No. 5 were terminated at short lengths when clays were encountered and the drill pipe twisted off. The first five holes were drilled in the Middle Lakota Sand

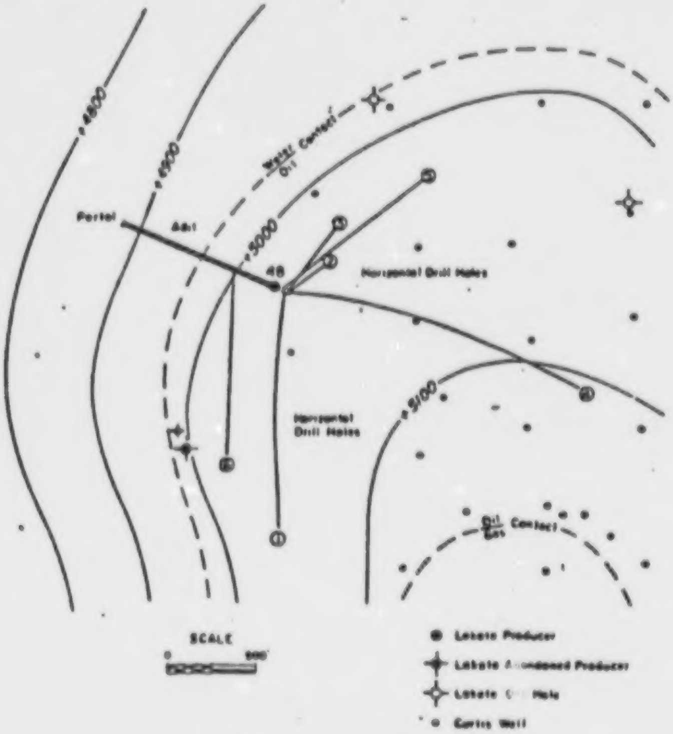

Fig. 6 - Horizontal Drainhole Pattern.

and the sixth hole tested the productivity of the Upper Lakota Sand. The Upper Lakota was found to be non-productive and the drainhole was deviated and completed in the Middle Lakota Sand.

Directional surveying of the drainholes was done at 35 ft (10.7 m) to 50 ft (15.2 m) intervals using a special Sperry Sun survey tool which was pumped down the internally flush drill pipe and retrieved with a wireline winch. Deviation in the vertical plane was controlled by the amount of thrust placed on the bit. The typical deviation range was ± 5 ft (1.5 m). Horizontal deviation was not as easily controlled. Drilling records indicate that the bit tended to drift upstructure. It was determined that a near bit square stabilizer with additional stabilizers in the drill string would produce a relatively straight hole.

The drill assembly was developed primarily for use in drilling coal. Sandstone, being a much more abrasive material, caused several problems with the equipment. Drill pipe failure due to insufficient pipe wall strength was quite common, and a great deal of time was spent in fishing. Since the hole size and drill pipe size were non-standard, conventional oil field taper taps and spears had to be modified for fishing. The frequency of drill pipe failures was reduced later in the drilling by the addition of a polymer in the fresh water mud system. The polymer reduced friction between the pipe and hole wall and inhibited the swelling of clays.

Bit selection to accommodate the sand was initially a problem. Carbide insert bits were tried, but penetration rates were very poor and the bits dulled rapidly. Cone bits were also tried, but it was found that they tended to wander regardless of the thrust applied. A specially designed diamond bit proved to be the best performer. In addition to good deviation control, penetration rates averaged 3.3 ft/min. (1.0 m/min.) and rates as high as 6.7 ft/min. (2.0 m/min.) were obtained several times. The average footage drilled during a good eight-hour shift was 125 ft (38.1 m).

Separation of the drill cuttings from the mud system was accomplished in three 4 ft x 8 ft x 2.5 ft high (1.2 m x 2.4 m x 0.8 m) mud tanks located underground near the drill. Fluid was siphoned off the top of each successive tank and piped into a centrifugal mud pump. Very early in the drilling it was evident that extremely fine powdered sand was carrying through the mud system causing damage to the pump. The problem was solved by installing a progressing cavity pump with a flexible rubber stator. When the mud tanks were filled with cuttings, they were hauled out to the surface and dumped.

Production Controls

The pumping unit on Well No. 48 is controlled by a level sensing bubble tube apparatus located in the underground main production sump. A constant air flow rate of 2 CFH (0.057 m^3/hr.) travels down a 1/2 in. (1.3 cm) open ended tube which is submerged in the sump. The hydrostatic head above the bottom of the bubble tube is transmitted as air pressure to a pair of head switches at the surface. As the liquid level on the sump reaches a preset level, the pump is started. As the fluid level drops to a preset low level, the pump is stopped.

Drainhole No. 6 is located approximately 250 ft (76.2 m) back from the face of the adit and the main production sump. This required the installation of a small sump at No. 6 with two air-operated diaphragm pumps to transfer fluid to the main sump. One pump is the primary fluid transfer pump, and the second pump acts as a back up. The back up pump operates in the event of a primary pump malfunction and also when a high fluid level exists in the sump. These pumps are controlled by float switches which automatically start and stop the pumps.

The fire alarm system is comprised primarily of 1/4 in. (0.6 cm) polyethylene tubing hung from the mine roof in the oil saturated section of the adit. The tubing is connected to an air actuated cylinder and fire-safe valve on the drainholes. A compressor on the surface supplies a constant 50 psi (446 kPa) pressure to the system, holding the fire-safe valves in an open position under normal operations. In the event of an underground fire or explosion, the polyethylene tubing will melt causing a loss of air pressure and thereby automatically shut in the drainholes to prevent produced oil from continuously feeding a fire.

The operation of the ventilation system is constantly monitored by a flow-no-flow and vacuum/pressure probe in the ventilation piping. If a continuous flow of air past these monitors is not maintained, an air operated siren is activated which is audible both underground and on the surface. It must be noted that due to mining regulations, ventilation must be maintained at all times. However, during the producing life of the project a low volume fan moves air at approximately 7000 CFM (198 m^3/min.) when no personnel are in the mine. The main, or high volume fan, which was used during drilling, must be used when any personnel enter the mine. This fan will move air at a rate of 17,000 CFM (481 m^3/min.).

A washline system consisting of 1-1/4 in. (3.2 cm) black pipe has been installed in three of the six drainholes. The purpose of the washline is to flush accumulated sand which may collect in the drainholes and also to provide a means for various stimulation treatments. The washline system is connected to the surface through the 5-1/2 in. (14.0 cm) service hole drilled into the mine.

In addition to these alarms and controls, a telephone communication system between the surface and underground has been installed. The telephones are located at two stations underground, one at the portal and one at the surface location of Well No. 48.

The adit is entered and inspected by personnel trained in accordance with state and federal laws. The project was initially inspected monthly to make final control adjustments on the production equipment. All maintenance procedures are now done on a quarterly basis. In addition to the company inspection, the project is also inspected quarterly by a Deputy State Mine Inspector and a Federal Mine Safety and Health Administration Inspector.

Production Performance

Project construction and horizontal drilling were completed on August 3, 1979, and the producing phase of the project began. A total of 45,600 STBO (7250 m^3 and 12,544 BW (1994 m^3) have been produced from the project as of April 1, 1981. The average first year producing rate was 68 BOPD (10.8 m^3/d) and 28 BWPD (4.5 m^3/d). The initial decline of production was 56% per year; however, the initial sharp decline is due to depletion of the reservoir pressure. The production of fluids from the project is quickly depleting the low pressure (20 psi) remaining in the reservoir. Gravity drainage will become increasingly dominant as the pressure continues to decline. Production trends over the past three months indicate that a levelling out of the decline is beginning to occur showing the effect of a gravity drainage mechanism. It is now projected that the production will level out at approximately 25 BOPD (4.0 m^3/d) and decline at a rate of 6% per year.

Continued Lakota Development

The development of the Lakota is continuing in a similar manner. A 235 ft deep, 16 ft diameter shaft is being constructed to gain access to the sand. The shaft will be lined with a 1 ft thick concrete sheath, reducing the shaft internal diameter to 14 ft. At the base of the shaft, a 60 ft long x 10 ft high x 18 ft wide chamber will be excavated. From this chamber four (4) 1500 ft long horizontal drainholes will be drilled. Once again, oil recovery will be due to the gravity drainage mechanism.

Initially, a 17 ft square collar section will be excavated to a depth of 15 ft using a backhoe. Concrete forms will be set so that the concrete sheath can be poured around the 14 ft ID hole.

After 15 ft, excavation will continue utilizing drill, blast, and muck methods. Five foot sections of rock will be drilled and blasted using explosive charges. The debris is mucked out every 10 ft using a crane and muck bucket to a depth of 60 ft. After 60 ft, mucking will be done using a cryderman. A cryderman is an air-operated mucker with a positive opening and closing clam (Figure 7). The entire assembly is mounted on vertical runners which are set in the center of the shaft. The cryderman is raised and lowered by a hoist. A 10 ft section of the concrete sheath is poured after each mucking interval.

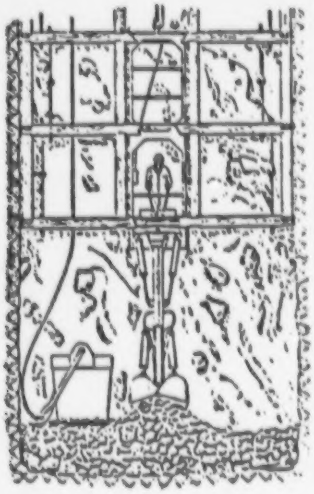

Fig. 7 - Cryderman Mucker in Vertical Shaft.

When the shaft reaches total depth (235 ft), the underground drilling chamber will be excavated at the base of it. This chamber will contain all of the underground equipment, including the production sump, horizontal drill, and an emergency refuge chamber. Surface facilities will be essentially the same as what is used at the adit.

CONCLUSION

The Lakota Gravity Drainage Project at North Tisdale provides a successful example of how mining methods can be used to recover oil. As the new technology associated with mining for petroleum is improved, these techniques will undoubtedly be applied in other areas to other low pressure oil reservoirs.

Experimentation with various stimulation treatments such as chemical wash treatments, a carbon dioxide flush, and possible experimentation with steam injection is also being considered for the horizontal drainholes.

In summary, the North Tisdale Gravity Drainage Project has illustrated that:

1. Mining for petroleum is a technically feasible concept in a shallow low pressure sandstone reservoir; and
2. Improvements in horizontal drilling equipment will increase operational efficiency and reduce costs.

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Mining Technology Assists Oil Recovery From Wyoming Field

(51)

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D.R. Seelye, SPE, Conoco Inc.

Summary

An unusual oil recovery project in Wyoming combines aspects of mining and petroleum engineering technologies to increase production from the North Tisdale field. The project basically consists of a horizontal tunnel, or adit in mining terminology, conventionally mined into a hillside (Fig. 1). The adit provides access to the oil sand from which an array of horizontal drainholes were drilled to various lengths. At the present time it is the only project known to exist in the U.S. that produces oil with this method.

History

Using mining methods to produce petroleum from shallow deposits is not a new concept. Mining, in one form or another, has been used to recover various forms of petroleum for centuries. Its importance, however, has been overshadowed by conventional oilwell development since Col. Drake successfully drilled for oil in 1859. Petroleum mining can be traced back in history to before 5000 B.C. when deposits were mined in the Sinai Peninsula, Persia, and the Euphrates River valley. Ancient Egyptians used mined petroleum for embalming, and sailors have long known the value of tar mined from pits for making their vessels watertight. In more recent history, petroleum mining has been attempted in the U.S. with various degrees of success. Projects have been attempted in Pennsylvania, Ohio, California, Texas, Kansas, Utah, and now Wyoming. It was used in the late 1800's primarily as an alternative to conventional oilwell drilling and later as a means of recovering additional reserves from shallow, pressure-depleted reservoirs. In addition to the early U.S. oil mining attempts, two famous mining operations were developed successfully in the Pechelbronn field in France and in the Wietze field in Germany from 1917 to 1930. These mines were developed during a period of European history when oil was a commodity that was required almost regardless of the cost. In general, however, the petroleum industry has turned away from oil mining as a viable recovery method because of the more favorable economic factors associated with conventional drilling development. Recent developments in world oil supplies and prices now are providing producers with incentives to experiment with mining as an oil-recovery technique.

Lakota Development

The North Tisdale oil field is located in the Powder River basin approximately 70 miles (112.6 km) north of Casper, WY (Fig. 2). Production was discovered in the field in 1952 from the Curtis sandstone at a depth of 1,000 ft (304.8 m). The discovery well had oil shows in the shallower Lakota sand, and the following year the first productive Lakota well was drilled. It was completed with 24 BOPD (3.8 m^3/d oil) and 2 BWPD (0.3 m^3/d water) from a zone at 210 ft (64 m). Before this discovery, the Lakota was known to be oil-productive in the area. Local history relates tales of early homesteaders and travelers who used oil obtained from seeps to lubricate wagon wheels.

The Lakota has provided a special challenge since development began in 1953. Production from early wells indicated that the reservoir initially produced through a weak gas drive that was replaced by gravity drainage shortly after completion. Local outcrops have allowed gas to escape and deplete the Lakota reservoir pressure. Conventional oil wells exhibit low initial producing rates and long producing lives typical of gravity drainage. Lakota development was slow because of marginal economics of the low-volume wells. A total of six producing wells were drilled during 1953–62 that had average initial producing rates of 8 BOPD (1.3 m^3/d oil) and 3 BWPD (0.5 m^3/d water) (Fig. 3). Engineers recognized that less than 2% of the oil in place would be recovered from the Lakota by primary methods. As a

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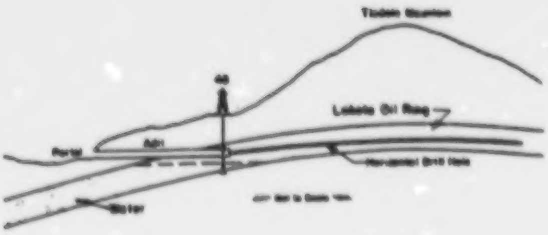

Fig. 1—Generalized conception of project.

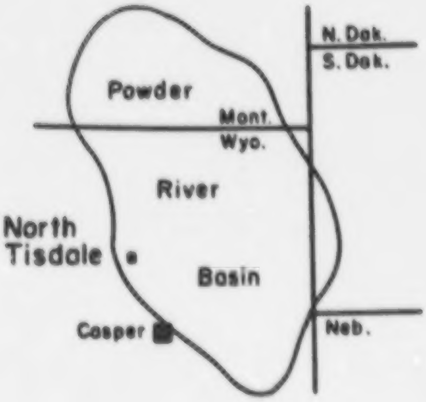

Fig. 2—North Tisdale location map.

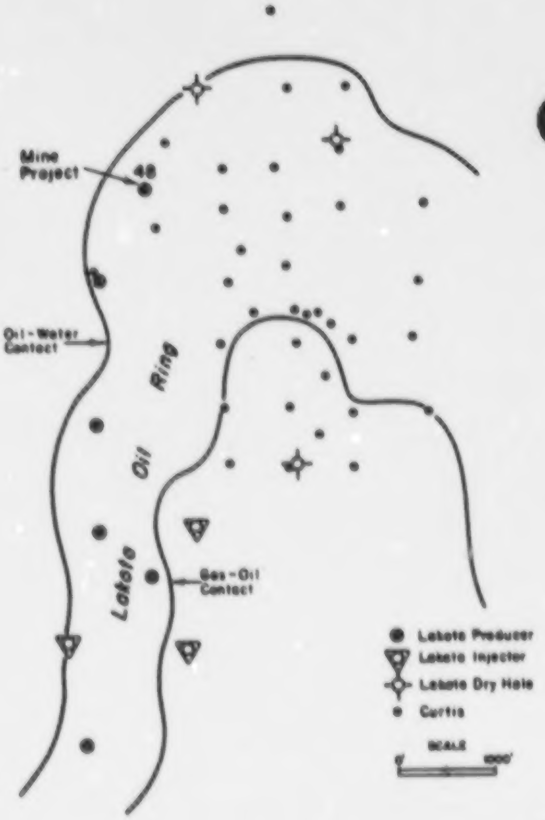

Fig. 3—North Tisdale producing wells.

result, a one-injection-well pilot waterflood was tested in 1961 to investigate the feasibility of waterflooding the Lakota. The injection well produced a slight response in an offsetting producer. The one-well project was expanded to a single five-spot pattern to test the application of a fieldwide flood. The project was installed in 1962 and was discontinued after a significant volume of water was injected and no production or pressure response was noted in the central producing well or in offset producers. Lakota development halted after the pilot waterfloods because of a lack of success and poor economics. By 1972, all but three of the Lakota wells in the field were plugged, and of these only one continued to produce at a rate of 1.5 BOPD (0.2 m^3/d oil) and 1 BWPD (0.2 m^3/d water). Total conventional recovery from the reservoir since discovery has been only 79,500 STB (12 64[illegible] stock-tank m^3) of oil.

Reservoir Characteristics

The North Tisdale field is located structurally on the asymmetric, north-plunging nose of the large Tisdale Mountain anticline. The steeper western limb of the anticline dips at 10° to 12°, and the eastern limb dips at approximately 4°. The Lakota structure generally parallels the surface topography of the mountain. The Lakota reservoir consists of a large gas cap surrounded by an oil ring that is further defined by a water/oil contact. The vertical depth reaches a maximum of 500 ft (152.4 m) on the crest and ridges of the mountain and decreases in depth in the eroded draws. A number of outcrops are evident in the most severely eroded draws. The average depth of the Lakota is approximately 300 ft (91.4 m) across the field.

The Lakota sandstone consists primarily of a thin, tight upper sand interval and a thicker, oil-productive middle sand section separated by a thin shaly zone. A water-saturated lower sand is also apparent in some areas of the field. The upper sand averages 12 ft (3.6 m) in gross thickness and generally is described as a light gray, well-cemented, medium-to-fine-grained sandstone with spotty oil saturation. The middle Lakota averaged 40 ft (12.2 m) in gross thickness and consists of a light gray to tan, medium-grained calcareous sandstone. Well data indicate that the total gross Lakota thickness varies from 30 to 100 ft (9.1 to 30.5 m), with an average thickness of 58 ft (17.7 m). Geological interpretations indicate that the thickness variations and the occasional absence of the lower sand are a result of channeling into the underlying Morrison formation.

The middle Lakota sandstone exhibits reservoir rock and fluid properties that make it a good candidate for gravity drainage development. Gravity flow rates depend primarily on permeability, oil viscosity, and formation dip. The sand has an average porosity of 18.9% and horizontal permeability to air ranging from 45 to 3,000 md. Saturation determinations from log and core data in-

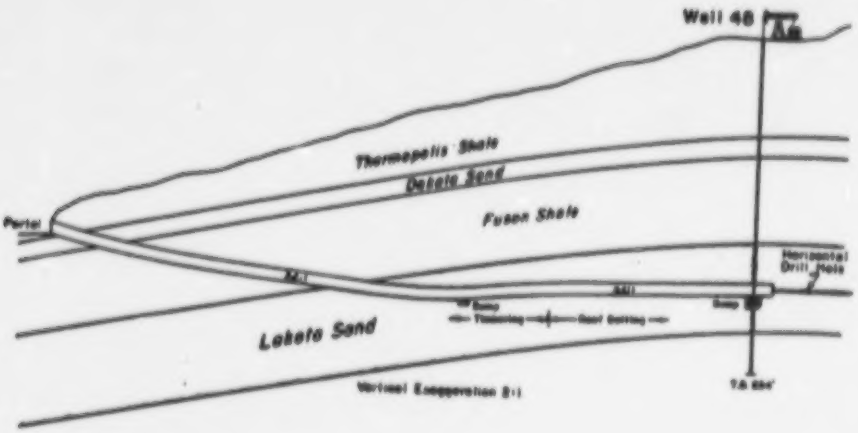

Fig. 4—Actual adit cross section.

dicate water saturations in the range of 40 to 50%. Net pay averages 21 ft (6.4 m) of sand with porosity greater than 10%. The 28° API (0.89-g/cm^3) gravity Lakota crude has a viscosity of 19 cp (0.019 Pa·s) at 70°F (21.1°C) and a pour point of −10°F (−23.3°C). Average reservoir temperature is estimated to be 60°F (15.6°C). From these data, a value of 733 bbl/acre-ft (4116 m^3/m^3) of original oil in place has been estimated.

Planning and Design

In the mid-1970's, rising oil prices caused renewed interest in the Lakota, which had remained essentially undeveloped at North Tisdale since 1962. To recover more "known" Lakota oil, an experimental project was begun with mining techiques to gain access to the sandstone and drill long horizontal drainholes into the reservoir. A much larger surface area would be created by a horizontal drainhole, and a higher oil production rate would be obtained than was possible with a conventional vertical wellbore. Two alternatives were investigated as possibilities for gaining access to the Lakota reservoir: (1) drive a horizontal adit into the side of the mountain or (2) sink a vertical shaft. Geological and mining personnel were consulted to aid in selecting the best approach. Personnel requirements, training requirements, specialized mining equipment, cost, and other factors were considered to determine that a horizontal adit would be the most feasible first choice.

Geologists and engineers selected the project site by combining topographic, geologic, and reservoir information. The site was located near the oil/water contact to maximize oil recovery by gravity drainage. Several mining, environmental, and drilling permits were applied for and obtained from various state and federal agencies after the mine site was chosen. Well 48 was drilled in May 1977, to verify the presence of oil-saturated reservoir rock and confirm the mine site. Well 48 also provided information on the depth of the oil/water contact and indicated the angle of decline that the horizontal adit would require to intersect the Lakota sand. Well logs and drill cuttings indicated the Lakota top at 143 ft (43.6 m) and the top of the middle Lakota sand at 162 ft (49.4 m). Approximately 25 ft (7.6 m) of oil-saturated reservoir was evident. It was determined that this section of the middle Lakota in Well 48 would be the target point for the adit.

Mining Phase

In June 1977, portal construction for the adit was completed. A steel security door was installed and the actual mining activity was initiated. Mining was accomplished with conventional drilling, blasting, and mucking equipment by a local Wyoming contractor. Mining of an adit 9 ft (2.7 m) wide by 8 ft (2.4 m) high proceeded by drilling holes 1 in. (2.5 cm) in diameter and 5 ft (1.5 m) in length with a pneumatic drill. Several of these holes were drilled into the advancing face of the adit and packed with explosive charges. The charges were detonated from outside the adit. Specialized mining front end loaders then cleaned (or mucked) out the rock debris. The initial 550 ft (167.6 m) of the adit were driven through weathered sections of the Fuson shale. The instability of these shales required use of conventional timber supports. Ground movement associated with small faults and swelling of the bentonitic clays in the shales during seasonal wet periods required the installation of steel beams in place of timber for adequate support. At a length of 720 ft (219.5 m), the adit was well within the competent upper Lakota sand, and ground control methods were changed from timbering to roof bolting. A split-tube-type roof bolt was used, which consisted of a 5-ft (1.5-m) hollow steel tube, 1.5 in. (3.8 cm) in diameter, with an open gap along the entire length. The bolts are driven into a 1⅜-in. (3.5-cm) diameter hole with an air hammer. The friction between the tube and the wall of the hole provides resistance to ground movement. A standard chain link fencing was slipped over the rock bolts and pinned to the roof and walls as protection against sloughing and spalling rock. This type of support was continued until the mining was halted at a length of 985 ft (300.2 m), where the wellbore of Well 48 was intersected (Fig. 4).

The adit was ventilated during mining by air blown

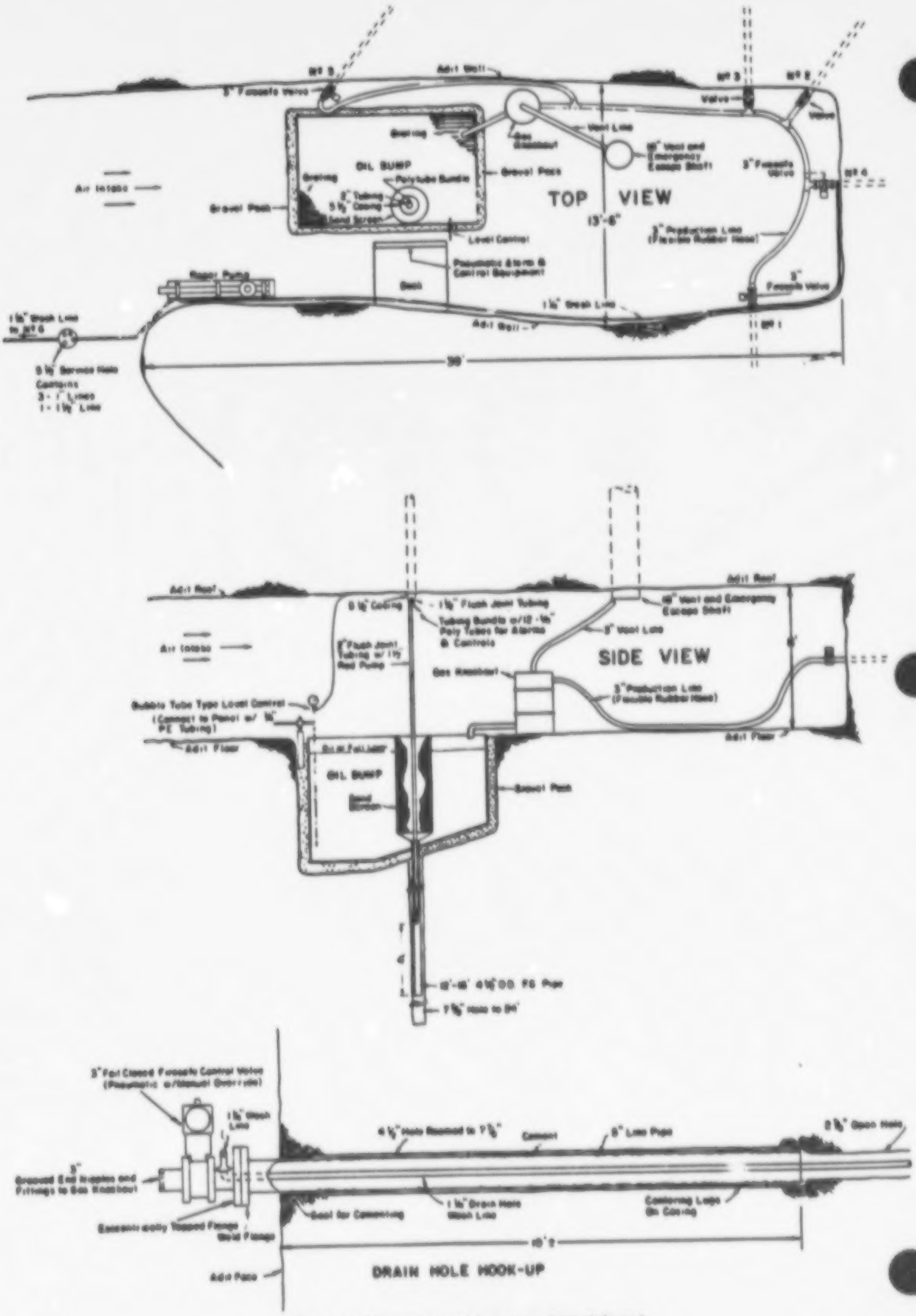
TOP VIEW
Nº 5
Adit Wall
3" Failsafe Valve
Grating
Gas Knockout
Vent Line
Oil Sump
Polytube Bundle
2" Tubing
5 ½" Casing
Sand Screen
Gravel Pack
Air Intake
Level Control
Pneumatic Alarm & Control Equipment
Desk
Rod Pump
1 ½" Wash Line to Nº 6
5 ½" Service Hole Contains 3 - 1" Lines 1 - 1 ½" Line
18" Vent and Emergency Escape Shaft
13'-6"
Nº 3
Nº 2
Valve
3" Failsafe Valve
Nº 4
3" Production Line (Flexible Rubber Hose)
1 ½" Wash Line
Nº 1
30'
SIDE VIEW
Adit Roof
5 ½" Casing
1 ½" Flush Joint Tubing
Tubing Bundle w/12 - ¼" Poly Tubes for Alarms & Controls
2" Flush Joint Tubing w/ 1 ½" Rod Pump
18" Vent and Emergency Escape Shaft
3" Vent Line
Gas Knockout
3" Production Line (Flexible Rubber Hose)
Bubble Tube Type Level Control (Connect to Panel w/ ¼" PE Tubing)
Adit Floor
Oil Sump
Sand Screen
Gravel Pack
12'-16' 4 ½" OD FG Pipe
7 ⅞" Hole to 24'
DRAIN HOLE HOOK-UP
3" Fail Closed Failsafe Control Valve (Pneumatic w/Manual Override)
1 ½" Wash Line
3" Grooved End Nipples and Fittings to Gas Knockout
Eccentrically Tapped Flange
Weld Flange
Adit Face
4 ½" Hole Reamed to 7 ⅞"
Cement
3" Line Pipe
2 ⅞" Open Hole
Seal for Cementing
1 ½" Drain Hole Wash Line
Centering Lugs On Casing
10'±

Fig. 5—Underground production equipment layout.

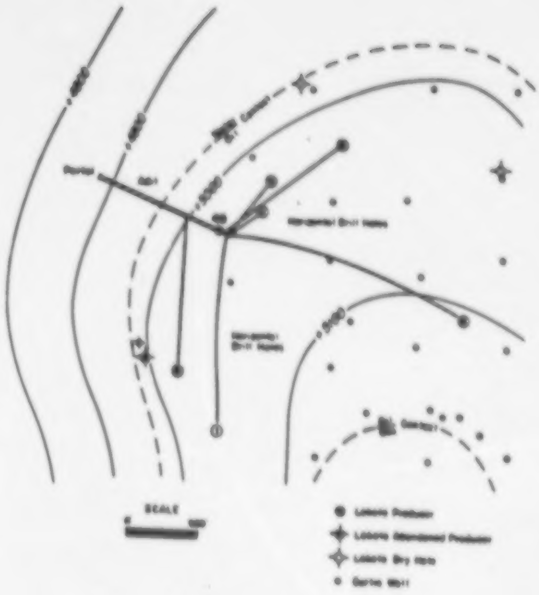

Fig. 6—Horizontal drainhole pattern.

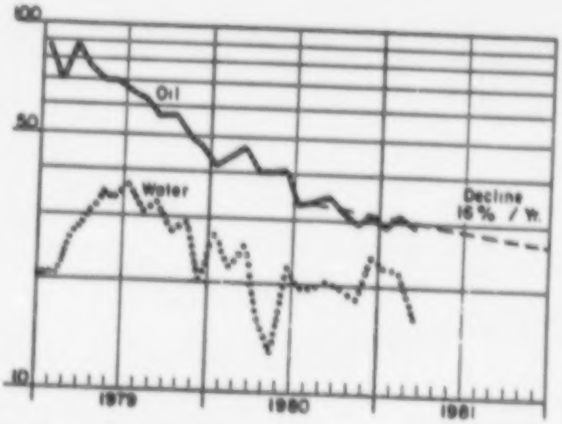

Fig. 7—Production performance curve.

down the length of the adit through 18-in. (45.7-cm) flexible tubing to the face. Before adit completion, a more permanent ventilation system was installed. A 22-in. (55.9-cm) hole was drilled to a depth of 176 ft (53.6 m) from Well 48 surface location and cased to 18 in. (45.7 cm). The adit then was advanced to intersect the ventilation shaft and a 30-hp (22.4-kW) vane axial reversible fan was installed on the surface. The flexible ventilation tubing used during construction was removed, and now ventilation is by fresh air drawn in the portal, down the length of the adit, up the vent shaft, and through the fan. It is critical for a safe mining operation to maintain an adequate fresh air flow through the mine. The ventilation system meets all requirements set forth by state and federal gassy mine regulations.

The vent shaft also doubles as an emergency escape route. An escape hoist and cage installed on the surface can be lowered into the mine to remove personnel in the event of an underground emergency. The hoist is powered by an electric motor and is equipped with a backup generator. The unit was installed and approved in accordance with state and federal mine safety regulations. These regulations require at least one qualified person on the surface at all times when personnel are underground.

At this point, final preparations were made to begin the horizontal drilling phase of the project. A steel production sump tank was bolted into the floor directly below Well 48 to serve as a collection point for produced fluids. A conventional beam pumping unit was installed on the surface; tubing, rods, and pump were run down to the sump (Fig. 5).

Drilling Phase

Specialized drilling equipment was used to drill the horizontal drainholes. The machinery had to meet several requirements: (1) the drill had to be compact and easily operated in the confined area, (2) it had to be safe for operation in a gassy atmosphere, and (3) it had to be easily controlled to correct for hole deviation. Deviation control was considered very important since it was desired to remain as close to the bottom of the oil-saturated sand section as possible. This would take full advantage of the oil column height and result in maximum recoverable reserves. The drilling equipment used at North Tisdale was developed by Conoco Mining Research Co. for coal seam degasification in underground mines. The compact drill utilized 5-ft (1.5-m)-long joints of 2.25-in. (5.7-cm) drillpipe to drill a hole 2⅞ in. (7.3 cm) in diameter. The equipment was capable of drilling a hole 2,000 ft (609.6 m) in length. The unit was operated totally by hydraulics and controlled by a portable valve-control panel located underground. An electrically driven hydraulic power pack was located on the surface, and hydraulic lines were run down a separate 5½-in. (14.0-cm) service hole drilled into the adit. Once the drilling equipment was oriented and secured in position, a hole 10 ft (3.0 m) long and 7⅞ in. (20.0 cm) in diameter was drilled into the wall. In this hole, a length of 5.5-in. (14.0-cm) line pipe was cemented to serve as conductor pipe during drilling and also to provide a means of controlling flow from the completed drainhole. The remaining length of each hole was left open to the sand. Six horizontal drainholes were drilled (Fig. 6). The holes and corresponding lengths are as follows.

Hole	Length (ft)	Length (m)	Hole	Length (ft)	Length (m)
1	1,498	456.6	4	1,700	518.2
2	248	75.6	5	970	295.7
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Holes 2, 3, and 5 were terminated at short lengths when clays were encountered and the drillpipe twisted off. The first five holes were drilled in the middle Lakota sand, and the sixth hole tested the productivity of the upper Lakota sand. The upper Lakota was found to be nonproductive and the drainhole was deviated and completed in the middle Lakota sand.

Directional surveying of the drainholes was done at 35- to 50-ft (10.7- to 15.2-m) intervals using a special Sperry Sun survey tool that was pumped down the internally flush drillpipe and retrieved with a wireline winch. Deviation in the vertical plane was controlled by the amount of thrust placed on the bit. The typical deviation range was ±5 ft (1.5 m). Horizontal deviation was not as easily controlled. Drilling records indicate that the bit tended to drift upstructure. It was determined that a near-bit square stabilizer with additional stabilizers in the drillstring would produce a relatively straight hole.

The drill assembly was developed primarily for use in drilling coal. Sandstone, being a much more abrasive material, caused several problems with the equipment. Drillpipe failure as a result of insufficient pipe wall strength was quite common, and a great deal of time was spent in fishing. Since the hole size and drillpipe size were nonstandard, conventional oilfield taper taps and spears had to be modified for fishing. The frequency of drillpipe failures was reduced later in the drilling by the addition of a polymer in the freshwater mud system. The polymer reduced friction between the pipe and hole wall and inhibited swelling of clays.

Bit selection to accommodate the sand was initially a problem. Carbide insert bits were tried, but penetration rates were very poor and the bits dulled rapidly. Cone bits were tried also, but they tended to wander regardless of the thrust applied. A specially designed diamond bit proved to be the best performer. In addition to good deviation control, penetration rates averaged 3.3 ft/min (60 m/s) and rates as high as 6.7 ft/min (120 m/s) were obtained several times. The average footage drilled during a good 8-hour shift was 125 ft (38.1 m).

The drill cuttings were separated from the mud system in three 4-×8-×2.5-ft high (1.2-×2.4-×0.8-m high) mud tanks located underground near the drill. Fluid was siphoned off the top of each successive tank and piped into a centrifugal mud pump. Very early in the drilling, it was evident that extremely fine powdered sand was carrying through the mud system, causing damage to the pump. The problem was solved by installation of a progressing cavity pump with a flexible rubber stator. When the mud tanks were filled with cuttings, they were hauled out to the surface and dumped.

Production Controls

The pumping unit on Well 48 is controlled by a level sensing bubble tube apparatus located in the underground main production sump. A constant air flow rate of 2 cu ft/hr (0.057 m^3/h) travels down a 0.5-in. (1.3-cm) open-ended tube that is submerged in the sump. The hydrostatic head above the bottom of the bubble tube is transmitted as air pressure to a pair of head switches at the surface. As the liquid level on the sump reaches a preset level, the pump is started. As the fluid level drops to a preset low level, the pump is stopped.

Drainhole 6 is located approximately 250 ft (76.2 m) back from the face of the adit and the main production sump. This required the installation of a small sump at Drainhole 6 with two air-operated diaphragm pumps to transfer fluid to the main sump. One pump is the primary fluid transfer pump, and the second pump acts as a backup. The backup pump operates in the event of a primary pump malfunction and also when a high flu level exists in the sump. These pumps are controlled float switches that automatically start and stop the pumps.

The fire alarm system is comprised primarily of 0.25-in. (0.6-cm) polyethylene tubing hung from the mine roof in the oil-saturated section of the adit. The tubing is connected to an air-actuated cylinder and fire-safe valve on the drainholes. A compressor on the surface supplies a constant 50-psi (446-kPa) pressure to the system, holding the fire-safe valves in an open position under normal operations. In the event of an underground fire or explosion, the polyethylene tubing will melt, causing a loss of air pressure, and thereby automatically will shut in the drainholes to prevent produced oil from continuously feeding a fire.

The operation of the ventilation system is monitored constantly by a flow/no-flow and vacuum/pressure probe in the ventilation piping. If a continuous flow of air past these monitors is not maintained, an air-operated siren is activated, which is audible both underground and on the surface. Note that because of mining regulations, ventilation must be maintained at all times. However, during the producing life of the project, a low-volume fan moves air at approximately 7000 cu ft/min (198 m^3/min) when no personnel are in the mine. The main or high-volume fan, which was used during drilling, must be used when any personnel enter the mine. This fan will move air at a rate of 17,000 cu ft/min (481 m^3/min

A washline system consisting of 1.25-in. (3.2- black pipe has been installed in three of the six drainholes. The purpose of the washline is to flush accumulated sand that may collect in the drainholes and also to provide a means for various stimulation treatments. The washline system is connected to the surface through the 5.5-in. (14.0-cm) service hole drilled into the mine.

In addition to these alarms and controls, a telephone communication system between the surface and underground has been installed. The telephones are located at two stations underground, one at the portal and one at the surface location of Well 48.

The adit is entered and inspected by personnel trained in accordance with state and federal laws. The project initially was inspected monthly to make final control adjustments on the production equipment. Now all maintenance procedures are done on a quarterly basis. In addition to the company inspection, the project also is inspected quarterly by a deputy State Mine Inspector and a Federal Mine Safety and Health Admin. Inspector.

Production Performance

Project construction and horizontal drilling were completed on Aug. 3, 1979, and the producing phase of the project began. A total of 52,050 STB (8275 stock-tank m^3) of oil and 22,525 bbl (3581 m^3) of water have been produced from the project as of Oct. 1, 1981. average first year producing rate was 68 BOPD (m^3/d oil) and 28 BWPD (4.5 m^3/d water) (Fig. 7). Th initial decline of production was 56% per year; however, the initial sharp decline is a result of gas cap expansion. The production of fluids from the project is quickly depleting the low pressure remaining in the reservoir. Gravity drainage will become increasingly dominant as the pressure continues to decline. Production trends over past months indicate that a leveling out of the decline is occurring, showing the effect of a gravity drainage mechanism. Production is currently 28 BOPD (4.5 m^3/d oil) and is declining at approximately 16% per year.

Conclusions

The Lakota Gravity Drainage Project at North Tisdale provides a successful example of how mining methods can be used to recover oil. Development of the Lakota is continuing in the area with a vertical shaft. A large-diameter shaft has been constructed to provide an access to an underground drilling chamber. Horizontal drainholes will be drilled from the underground chamber into the reservoir in a manner similar to the first project. However, the horizontal drilling equipment has been redesigned to reduce downtime resulting from mechanical failure and drillpipe twist-offs. As the new technology associated with mining for petroleum is improved, these techniques undoubtedly will be applied in other areas to other low-pressure oil reservoirs. In summary, the North Tisdale Gravity Drainage Project has illustrated that:

1. Mining for petroleum is a technically feasible concept in a shallow, low-pressure sandstone reservoir.
2. Improvements in horizontal drilling equipment will increase operational efficiency and reduce costs.

SI Metric Conversion Factors

in. × 2.54* E+00 = cm
ft × 3.048* E−01 = m

*Conversion factor is exact.

JPT

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Application of Horizontal Wells at Prudhoe Bay

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ABSTRACT

Horizontal wells have been shown to increase productivity, reduce coning tendencies and increase recovery. Given the potential applications in the Prudhoe Bay Field, a project has been ongoing for the past 18 months to evaluate benefits and drill and test three trial wells.

This paper reviews production and reservoir engineering aspects of the trial program. It includes the objectives of the test program, a discussion of the screening and ranking of prospective well locations, the planning and drilling of three wells, the forecasting of production rates and additional recoveries, and the testing and analysis of actual well performance.

Drilling aspects of the program have been reviewed in another paper presented at this conference.[1]

In summary, the three wells have been successfully drilled and completed, with each well costing less than its predecessor. The two wells tested to date have exhibited productivities three to four times that of a conventionally completed comparison well, and further productivity increases are thought to be possible.

INTRODUCTION

The idea of using horizontal wells to increase the area of reservoir contacted dates back to the early 1940's. However, until recently there has been little interest in spending additional money on a new technique when most reservoirs can be economically produced by conventional methods such as fracture stimulation.

Recently, the usefulness of horizontal wells has been demonstrated in North America[2] and Western Europe.[3], [4] With current technology, horizontal wellbore distances that are much longer than the fracture lengths achieved by hydraulic fracturing are possible at moderate costs.

Horizontal wells can improve production rates and recoveries by a variety of mechanisms. At their most basic, the long wellbores allow longer completed intervals and therefore increased production rates. In reservoirs overlying an aquifer or located under a gas cap the increased standoff from the fluid contacts can improve the production rates practical without causing coning. Additionally, the longer wellbore length serves to reduce the drawdown for a given production rate and thus further reduce coning tendencies. Fractured reservoirs can also benefit from horizontal wells. Long wellbores are likely to intersect more fractures and hence improve both production rate and ultimate recovery. Furthermore, the application of horizontal wells early in a project may allow development with fewer wells, due to the larger drainage area of each well. In some fields the above mentioned advantages of horizontal drilling may allow development where conventional techniques would be uneconomic.

The development of the Prudhoe Bay oil field, on the North Slope of Alaska, has been extensively reviewed in published literature.[5],[6],[7] For reference a field outline showing waterflood and non-waterflood areas (Fig. 1), and a log section depicting the various zones (Fig. 2) are included.

Various areas of the field offer some of the potential advantages of horizontal drilling outlined above:

- The mid field area generally contains a thick remaining oil column overlain by an expanding

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References and illustrations at end of paper.

gas cap. Because in the near future Prudhoe Bay will become a field where production is constrained by the ability to compress and reinject produced gas, rather than by oil productivity, immediate field production rate increases will result from reducing gas coning. In excess of 250 additional infill wells on 80 and 40 acre spacing may ultimately be drilled and the potential for completing some of these as horizontal wells is significant.

- The upstructure areas offer similar possibilities although the sands are of generally lower quality and the oil column is thin.

- The extreme downstructure part of the Prudhoe reservoir is undeveloped. The thin oil column and potential problems caused by water coning from the underlying aquifer have made development relatively unattractive to date. Horizontal wells offer the possibility of reduced coning and increased production rates, perhaps increasing the attractiveness of development.

- The Eileen West End project involving development of the 100'-150' thick reservoir to the west of the already developed main area has recently been initiated. The drilling of 72 wells in this area is scheduled to begin in 1987 and the possibility of converting some conventional wells to horizontal wells exists. The advantage would be reduced gas and water coning, and reduced numbers of wells being required to obtain the same oil recovery.

Projected remaining oil at abandonment for the entire field is approximately 12 billion stock tank barrels, a significant target for any improved recovery scheme such as horizontal drilling.

THREE WELL TRIAL PROGRAM

Initially three non-conventional drilling concepts were considered for application in Prudhoe Bay:

Drainholes - Drainholes could be drilled from existing wells by deviating a sidetrack to the horizontal. Angle is built through a very short radius.

When comparing the use of a drainhole to that of a horizontal well some advantages exist in favor of the drainhole:

1. Drainholes can be drilled from existing wellbores. The cost of the vertical section is nil.
2. Geologic control is available in the vicinity of the drainhole, from the conventional well.
3. The total footage drilled is less for a drainhole than for a horizontal well.

Horizontal Wells - Horizontal wells are simply conventional wells deviated to the horizontal during drilling. Needless to say, this complicates the conventional drilling and completion program, and special equipment and drilling mud may be desirable.

The advantages of a horizontal well over a drainhole include:

1. Greater horizontal lengths are available with the horizontal well. The drainhole limit is ±400' with available technology whereas horizontal sections of 2000' have been reached in horizontal wells.
2. Conventional tubulars can be run in horizontal wells (casing, slotted liners, etc.), whereas special tools are required for entering a drainhole.
3. Measurement while drilling (MWD) tools can be a part of the drilling assembly in horizontal wells. No such tools can currently be used in the drilling of a drainhole.
4. Logs and cores, though expensive, are attainable in a horizontal well. These operations cannot be performed in a drainhole.

High Angle Wells - High angle (80°-90°) wells may offer advantages over truly horizontal wells in areas where severe vertical stratification exists. Where horizontal wells may penetrate only one sand, high angle wells may penetrate multiple sands and still offer advantages of increased wellbore length.

Based on the fact that many wells remain to be drilled in Prudhoe Bay, on the advantages outlined above, and on preliminary cost estimates, it was decided to concentrate early studies on horizontal wells. Drilling technology and drainage area considerations limited design length for the first wells to 1500'. Existing and planned waterflood areas were excluded from horizontal drilling consideration for initial locations.

A list of potential well locations, and a list of criteria were developed. The criteria were as follows:

Required Objectives

- Step-out of 5000' or less to the beginning of the horizontal section (At Prudhoe Bay all wells are drilled from centralized gravel pads and are therefore deviated. Targets are normally 8500'-9000'deep).

- Locations to be at least 5000' away from water injectors.

- Facilities are or will be available by mid-1986 for production testing of wells.

- All locations constitute planned infill locations.

Desired Objectives

- Mechanical success
  - Simple to drill
  - Successful isolation of the gas cap.
- Reservoir success
  - Provide rate benefits
  - Provide additional recovery benefits
  - Evaluate gas coning
  - Evaluate water coning.
- Reasonable geologic control
  - Low risk of fault intersection
  - Area of low structural dip
  - Low risk of encountering continuous shales.
- Optimum directional profile.
- Comparison to offset conventional wells is available.

The advantages and disadvantages of each location were reviewed. A three well program was selected as no single well could answer all questions. The selected well locations are shown on Fig. 3 and are discussed briefly below:

First Well Location JX-2 - This location best met the objectives described above.

Second Well Location B-30

The second horizontal well was not to be spudded until after the initial well was tested. This second well increased drilling experience prior to the more difficult drilling associated with the Y-20 location. This experience factor and the additional reservoir performance data justified two horizontal wells in the mid field area.

Third Well Location Y-20

Y-20 was recommended as the third horizontal well. This would be an extended reach well drilled after B-30. The thin oil column in the periphery and longer stepout made this more difficult to drill and higher risk. Horizontal drilling experience gained from the two initial horizontal wells in the mid field area reduced the drilling risk and increased the chances of a successful peripheral well.

The stepout for the commencement of the horizontal section was approximately 8300 feet. This exceeded the 5000 foot stepout restriction placed on the first well. However, information gained on the first two wells was designed to permit a stepout of this magnitude.

EVALUATION OF BENEFITS

Empirical, analytical, and numerical simulation methods were used to forecast the benefits of the horizontal wells planned for Prudhoe Bay. The benefits are considered under three headings: Productivity, Critical Coning Rates, and Additional Recovery.

Productivity

The productivity of a conventional well is proportional to the permeability thickness product. Low productivities result from low values of permeability or formation thickness (or both). This can be compensated for in horizontal wells where the length of the horizontal section is not imposed by nature but chosen. The permeability length product in horizontal wells plays a similar role to that of the permeability thickness product of conventional wells.

The productivity index of horizontal wells is given by[8],[9]:

$$PI = \frac{7.08 \times 10^{-3} k}{\mu B_o} \frac{1}{\frac{1}{h} \ln\left(\frac{1+\sqrt{1+(L/2r_e)^2}}{L/2r_e}\right) + \frac{1}{L} \ln\left(\frac{h}{2\pi r_w}\right)} \qquad \ldots (1)$$

The productivity index of vertical wells is given by:

$$PI = \frac{7.08 \times 10^{-3} kh}{\mu B_o \ln\left(\frac{r_e}{r_w}\right)} \qquad \ldots (2)$$

The effect of vertical well partial penetration can be incorporated into equation (2) via the skin term, as a pseudo skin.[10]

The effects of an anisotropic medium can be accounted for in equation (1) by a process of coordinate transformation, as demonstrated by Giger et al.[8] Fig. 4 is an example of productivity ratios with varying K_v/K_h values for a typical mid field Prudhoe Bay location.

It can be seen that vertical permeability has a significant effect on the gains achievable with horizontal wells. The initial horizontal well target locations are in areas where the K_v/K_h rate is thought to be in the range 0.1 to 0.5. With wellbore lengths of 1500' productivity gains by factors of five to ten are possible.

Critical Coning Rates

For Prudhoe Bay wells, gas critical coning rates have been defined by Addington:[11]

$$Q = (0.00725\ H)^{2.931} \left(\frac{K_h}{K_v}\right)^{0.1} \frac{K_h \sqrt{hp}}{B_o \mu_o\ F_1\ (F_2)^{0.1}} \qquad \ldots (3)$$

The critical rate for coning to occur in a horizontal well is[12,13]:

$$Q = 4.8 \times 10^{-3} \frac{k \Delta\rho h^2 L}{\mu_o B_o r_e} \left[1 - \frac{1}{6} \left(\frac{h}{r_e} \right)^2 \right] \quad \ldots (4)$$

Equation (4) can be used for either water or gas coning by using the appropriate value of $\Delta\rho$. The equation was developed using a model which assumes that the well crosses the entire width of the drainage area. This gives rise to a flow rate per unit length, which when multiplied by the wellbore length gives the critical coning rate for the well. The assumption does lead to a conservative value of the critical coning rate, as it does not consider the flow from beyond the ends of the well, which can be significant.

Fig. 5 shows critical coning rates of vertical and horizontal wells for one set of typical Prudhoe Bay reservoir conditions and various K_v/K_h ratios.

In reality future Prudhoe Bay wells will be produced not below critical coning rates, but at rates which fully utilize the available gas compression and reinjection facilities, thus maximizing oil production. Generally this will result in production above the critical coning rate. A numerical simulation model described below has been used to evaluate horizontal and conventional well performance under these conditions.

Additional Recovery

A variety of numerical simulation models were used to study the additional recovery attributable to the horizontal wells proposed for Prudhoe Bay. A commercially available, fully implicit, black oil simulation model was used in all these studies. The fully implicit calculation scheme assured complete stability of solutions. This proved to be an important feature, since the study required small grid blocks to evaluate gas and water coning tendencies which in some cases caused several grid cell pore volumes of fluid to pass through a cell in a single timestep. IMPES and semi-implicit methods are insufficient to handle such a situation unless the timesteps are reduced to impractically small values.

Single Wells Models

The primary goal of this study was to estimate the additional recovery benefits associated with horizontal wells, compared to the equivalent vertical wells.

The areas studied were the three locations initially proposed as prospective targets. Due to uncertainties in some reservoir characteristics, the models were considered more as 'mechanistic' models with specific geology, rather than exact reservoir site specific models with proper fluid distributions and movements. A schematic of one of these models is shown in Fig. 6.

These models were set up assuming that the horizontal wells each produced initially at twice the rate of the vertical wells, and that they each drained 160 acres rather than 80 acres. The vertical and horizontal well cases were both run under the same gas and water production constraints and identical field pressure declines were assumed.

Results of this study showed the following horizontal well additional recoveries:

Well	Additional Recovery (MMSTB)
JX-2	6.12
B-30	5.40
Y-20	5.35

These are the incremental recoveries over a conventional vertical well completed in the same location.

Concern over the validity of these results due to the fixed drainage area assumption led to the construction of a multiwell model for the JX-2 location. This allowed calibration of the single well model results to the conditions existing in the field, where closed drainage boundaries do not exist.

Multiwell Model

The single well models described previously are felt to be optimistic because they assume closed drainage volumes. In reality much of the oil drained by a horizontal well would have been recovered by the surrounding conventional wells had it not been drilled. To calibrate the single well model results to the field a multiwell model of the JX-2 area was constructed.

The technique of local grid refinement was used to correctly model the near wellbore effects without adding unnecessary blocks to the reservoir portion of the matrix. In the local grid refinement technique, large grid blocks containing a vertical well are replaced with a two dimensional model representation of the well. Similarly, large horizontal well grid blocks are replaced with a finely gridded three dimensional model. This technique allowed the model to have relatively coarse refinement in the reservoir section (5.3 acre blocks) and refinement as fine as 0.005 acres (10' radius) around the vertical wellbore.

Fig. 7 is a physical representation of the areal gridding of the model. The horizontal well is represented with an 8x2x19 matrix which is finely gridded around the ends of the wellbore to account for the fluid flow geometry. Fig. 8 shows the vertical layering of the model. The model layers become increasingly thin as the horizontal well is approached, and then thicker after the OWC is crossed. This layering scheme optimizes the model treatment of coning around vertical wells and the formation of a gas wedge over the horizontal wellbore.

The 220 acre model was history matched with 6 years of production data from existing conventional wells. Pressure decline and major fluid contact movement was accurately simulated in the model. No attempt was made to match fluid production, since the no flow boundaries of the model are not representative of the field. Individual well performance was matched by comparing remaining oil column thickness and the date at which the well's individual GOR began rising. The coning behavior would not have been adequately modeled if the technique of local grid refinement had not been applied in the study.

The results quoted here are from a case where the horizontal well productivity was matched with the results of step rate and pressure build-up tests on JX-2. The model wells were produced with a limiting bottom hole pressure of 2500 psi, which equates to an average drawdown of 1000 psi over the time period examined. As Prudhoe Bay wells begin to produce at higher GOR levels, the field will reach a point where the gas handling facilities will be unable to cope with higher production rates. At this time the field will begin its decline in oil production rate. This effect is simulated in the model by applying an upper limit on allowable total gas production rate from the model. Gas processing capability was divided equally among producing wells (vertical or horizontal) in the model. The model has correctly predicted the oil rate and GOR since JX-2 has been on production.

Fig. 9 shows the total oil recovery that can be expected from the development scenarios studied. Additional recovery is seen when one 80 acre well is replaced by a horizontal well. The mechanism for this additional recovery is reduced GOR due to a decrease in gas coning. Fig. 10 is a plot of total model GOR vs. total model oil production. It is clear that GOR is always lower in the horizontal well case. In a gas rate limited environment this translates to higher oil production and additional recovery.

The incremental recovery that can be expected from the drilling of JX-2 over the drilling of a conventional 80-acre producer can be estimated at 2.0 MMSTB, a substantial recovery increase per well. This does not compare with single well studies that estimated a recovery from JX-2 of 6.12 MMSTB. The discrepancy between the two values is due to the multiwell interaction effects present in the field. When the horizontal well is placed in an 80 acre location, it is evident that much of the oil recovered would have been produced by neighboring patterns had a vertical well been drilled, and cannot be considered additional recovery.

DRILLING SUMMARY

Table 1 summarizes the drilling times and costs for the three trial wells. Also shown is data for a typical conventionally drilled well. Note that as no conventional wells have been drilled with step outs comparable to Y-20, comparison for that well is invalid.

Analysis of JX-2 drilling times and costs shows that significant expenditures were incurred in determining the optimum bottom hole assembly required to build angle to 90°. The well was plugged back and sidetracked once so that the horizontal target would not be missed.

Analysis of times and costs on B-30 shows that major delays and costs were incurred as a result of a lost circulation problem experienced before the horizontal section was reached. This lost circulation is common in the area and is not related to horizontal drilling.

All wells were drilled to within a ± 15' vertical window along the entire length of the target.

From the experience gained future infill mid field wells with 1500' horizontal wellbores are expected to be drilled in a little over 30 days at a cost of approximately $3.8MM. This cost will include drill pipe conveyed open hole logs, as run on B-30, and the completion style described below.

COMPLETION

Typical Prudhoe Bay conventional wells are completed by setting 9 5/8" casing just above the reservoir and cementing a 7" liner through the formation. Production tubing is tied in to a packer set in the 9 5/8" casing and through tubing perforating guns are employed to bring wells on production.

The completion selected for the horizontal wells is depicted on Fig. 11. A 4 1/2" slotted liner lies in the 1500' horizontal section. The 5 1/2" tubing is tied into the top of the liner via a seal bore receptacle.

Reference to two phase flow regime correlations had shown that at low rates a large diameter, almost horizontal section of pipe could act as a downhole separator, decreasing hydraulic flow efficiency. For this reason the production tubing was not set into a packer further up the hole.

The use of a slotted liner rather than a cemented and perforated liner does limit future workover options, particularly in the event of excessive gas or water breakthrough. This completion was selected in the interests of simplicity and cost effectiveness. There are concerns over the practicality of performing adequate cement jobs in long horizontal wells, and the costs of perforating such a well are high.

TESTING AND ANALYSIS

JX-2 was put on production at the end of November 1985 and cleaned up for 6 days prior to testing. An offset conventional well, W-21, was tested immediately following the JX-2 test for comparison. B-30 was tested in March 1986 and it is considered to be in an area of comparable reservoir quality to JX-2 and N-21. Test results from the peripheral well Y-20 are not currently available.

All tests consisted of a multi-rate flow period to define the inflow performance relationship and a 24 hour pressure buildup. The inflow performance relationships (IPR curves) and the final buildup from each test are reviewed below, followed by a discussion of the results.

IPR Curves

Fig. 12 shows the IPR curve from JX-2 compared to conventional well N-21. It can be seen that the horizontal well is three to four times more productive than the conventional well. The JX-2 curve follows very closely a Vogel[14] type relationship, with a PI varying between 13.1 and 9.0 bbl/day/psi for the 6 rates tested. N-21 has a more linear relationship, with an average PI of 3.1 bbl/day/psi for the four rates tested.

Fig. 13 shows a comparison of the IPRs from JX-2 and B-30. Both wells show very similar curves even though B-30 is flowing with a 20% watercut. This water is thought to originate from water injectivity tests conducted in an offset well in 1979. The early decline in the water cut from 50%, to 16% today supports this view.

Horizontal Well Buildups

Following the six 12 hour flow periods used to define the IPR curve, JX-2 was shut in for a 24 hour pressure buildup.

Pressure buildup behavior in the vicinity of a long horizontal wellbore has been discussed in detail by Goode and Thambynayagam.[15] Normally, four flow periods, two radial and two linear, can be expected. In the case of JX-2 however, where the well is overlain by a large gas cap, only the initial radial flow period develops completely before pressure support from the gas cap makes any further pressure response unanalyzable. The initial radial flow period occurs in the vertical plane around the wellbore (Fig. 14) and can be analyzed by conventional techniques, the pressure behavior being similar to that of a conventional well lying on its side. It should be noted that reservoir properties interpreted during this initial flow period relate to the flow regime in existence, i.e., the thickness is equal to the wellbore length, the permeability is equal to the square root of the $K_v{*}K_h$ product, and the skin factor is the true damage skin. The calculated permeability thickness product therefore does not relate to the lateral reservoir transmissibility which ultimately may limit well productivity.

The horizontal well buildup analysis is complicated by the fact that the early time data is masked by wellbore storage effects and as previously mentioned the late time data is made unanalyzable by the boundary (gas cap) effects. Thus only a very short portion of the data is useful. A log pressure vs. log time plot for JX-2 is presented in Fig. 15; a derivative function is also plotted. This curve was matched to a derivative type curve for wells with damage and skin which is superimposed on the figure. No unique match was possible, however the results of an analysis most consistent with other known reservoir parameters is summarized in Table 2. In fact interpretations of a wide variation in transmissibility and skin are possible, but are considered less likely. Deterioration of the match beyond 0.5 hours is consistent with the limited standoff from the gas cap and good vertical permeability. The continuing rise in pressure observed in late time is most likely due to changes in the flow regime and drainage volume around the horizontal wellbore.

The pressure buildup behavior for B-30 (not shown) matched closely the JX-2 buildup, leading to a very similar, though also non-unique analysis.

Conventional Well Buildup

Following the four 12 hour flow periods used to define the N-21 IPR curve, this well was also shut in for a 24 hour buildup.

This test should be analyzable by more conventional means however, as in other Prudhoe Bay wells, the wellbore storage and gas cap effects severely limit the useful data. The log-log plot shown (Fig. 16) indicates clearly that no Horner straight line would be expected on a semi-log plot before the gas cap effect masks the pressure response. This test was analyzed using the type curves developed by Kirwan and Kucuk[16] for partially penetrating Prudhoe Bay wells. Again, due to the similarity of the type curves, a unique solution is not possible. A most consistent analysis is summarized on Table 3 and is discussed in detail below.

Discussion of Results

Initial production from JX-2 was a little disappointing in that a PI of 20 bbl/day/psi had been prognosed before drilling. The actual PI of 9-13 bbl/day/psi combined with the flow efficiency of 44% would suggest that the initial prognosis was, however, fairly accurate. During drilling the horizontal open hole was exposed to high weight mud containing fine drill solids for a long period. It is likely that formation damage occurred. Modifications to the mud program should avoid this problem in future wells.

Initial production from B-30 is affected by the presence of an increased water saturation. Log analysis indicated a saturation varying between 60 and 65% along the length of the well, compared to 50% in the vicinity of JX-2. The application of relative permeability relationships, and assuming a 4% critical gas saturation, indicates that effective permeability around the B-30 wellbore may be as low as one tenth of the absolute permeability. For comparison, the effective permeability with no free water present at JX-2 should be one half of the absolute permeability. It is anticipated that the productivity of B-30 will increase as the water cut declines.

Conventional well W-21 is completed with only 50' (35' TVD) at the base of the oil column perforated. This is the likely completion style of future wells where maximizing standoff from the gas-oil contact is vital to reduce coning and maintain production. Older wells with larger perforated intervals will eventually have to be worked over to increase standoff by reducing the perforated interval to similar, or lower, footage.

Considering the above, the results of W-21 testing are reasonable. The interpretation indicates a fairly small damage skin and a reservoir kh of 22400 md ft. For a well partially penetrating 15% of the oil column and with a high K_v/K_h ratio a partial penetration pseudo skin factor of 25 would be expected. This, combined with the reservoir kh measured, would suggest a PI of 4.0; very close to the observed value.

LONG TERM PERFORMANCE

Performance to date agrees well with forecasts calibrated to the observed PIs. In the Prudhoe Bay context the true test of these projections is long term GOR behavior. This will be closely monitored to determine gas breakthrough time, critical coning rate, and speed of GOR rise compared to conventional wells. In the case of the peripheral well, water-oil ratio and oil production rate will be the key monitoring parameters. Only then can the production benefits of horizontal wells be confirmed.

CONCLUSIONS

1. Initial results are good. The first two wells are three to four times more productive than the comparison conventional well. If this performance is maintained, forecasts suggest that these wells will each recover substantially more oil than would have been recovered by conventional wells.
2. Early projections of very high potential productivities, five to ten times that of conventional wells, although not achieved in the first two wells, are realistic.
3. The well costs required for horizontal drilling to be an economic success appear achievable. Current estimates are for wells with 1500' horizontal wellbores to cost 50% more than the conventional alternative wells.

NOMENCLATURE

B_o	Oil formation volume factor
F_1	(hp + oil column above perforations)/total oil column
F_2	Drainage area of wells in acres/160
H	Height from perforations to fluid contact (ft)
h	Reservoir thickness (ft)
h_p	Perforated interval (ft)
K	Permeability (md)
K_h	Horizontal permeability (md)
K_v	Vertical permeability (md)
L	Well length (ft)
PI	Productivity index (B/D/PSI)
Q	Flow rate (STB/D)
r_e	Drainage radius (ft)
r_w	Wellbore radius (ft)
S	Skin factor
μ	Viscosity (cp)
ρ	Density (gm/cc)

ACKNOWLEDGEMENTS

This project has been a multi-disciplinary effort involving Reservoir, Production, and Drilling Engineers, and Geologists. In particular we would like to recognize the contributions of the following: R. S. Allen, D. M. Chang, D. O. Cobb, P. A. Goode, T. O. Stagg, B. R. Stege, and D. J. Szabo. In addition, we would like to thank the management of Standard Alaska Production Company, and the other Prudhoe Bay Unit owners, for permission to publish this paper. It should be noted that the interpretations and conclusions discussed are the author's, and do not necessarily reflect the opinions of all the Prudhoe Bay owners.

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TABLE 1

Well	Spud Date	Drilling Time Days	Cost ($MM)	Cost/Foot ($)
JX-2	10/85	48	5.4	462
B-30	1/86	37	4.6	368
Y-20	4/86	31	3.9	282
Conventional		20	2.5	233

TABLE 2

JX-2 FINAL PBU 12/13/85

Pressure match point, $P_D/\Delta P$ = 0.76

Time match point, $(t_D/C_D)/t$ = 460

Skin, $C_De^{2s} = 10^{50}$

Following properties assumed:

q_o = 12340 STB/D

B_o = 1.3

μ_o = 1 cp

P_{wf} = 2418 psi

Pres = 3748 psi

Ct = 60×10^{-6}/psi

ϕ = 0.22

h_{wb} = 1500 ft.

r_w = 0.33 ft.

Results:

kh = 172 000 md ft (for 1500 ft wellbore, K = 115 md)

C = 0.11 bbl/psi

S = 57 (damage skin)

ΔP_s = 750 psi

Flow efficiency = 44%

TABLE 3

W-21 FINAL PBU 12/21/85

Pressure match point, $P_D/\Delta P$ = 0.043

Time match point, $(t_D/C_D)/t$ = 128

Skin, $C_De^{2s} = 10^{3}$

Following properties assumed:

q_o = 3090 STB/D

B_o = 1.3

μ_o = 1 cp

P_{wf} = 2740 psi

Pres = 3751 psi

Ct = 60×10^{-6}/psi

ϕ = 0.22

h = 200 ft.

r_w = 0.33 ft.

Results:

kh = 24400 md ft (for 200 ft formation k = 122 md)

C = 0.06 bbl/psi

S = 0.84 (damage skin)

ΔP_s = 20 psi

Flow efficiency = 98%

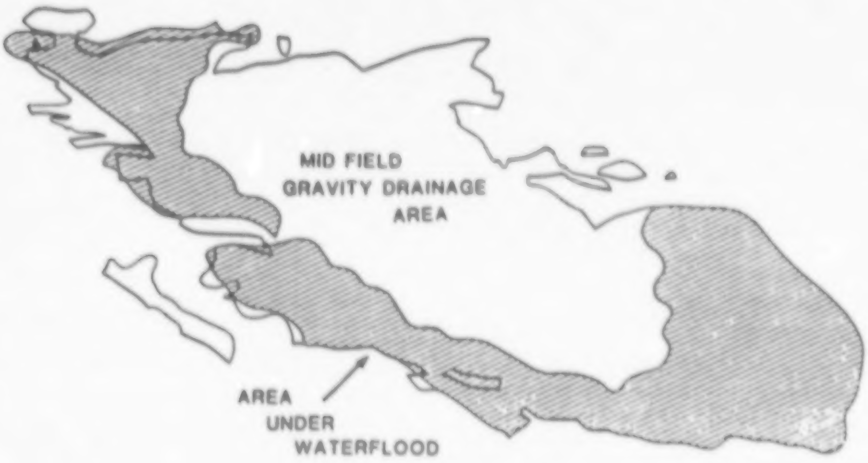

Fig. 1—Prudhoe Bay field (less than 100-ft oil column)

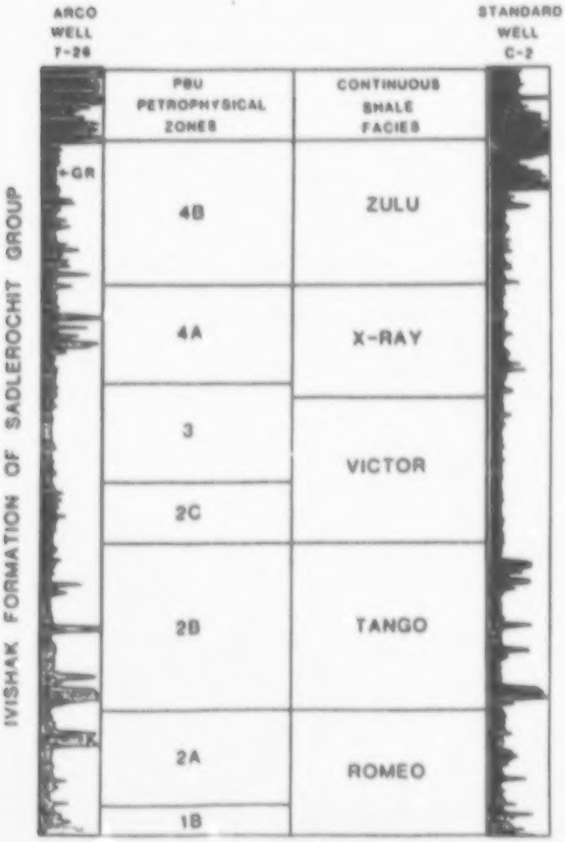

Fig. 2—Subzones of Ivishak/Sadlerochit at Prudhoe Bay

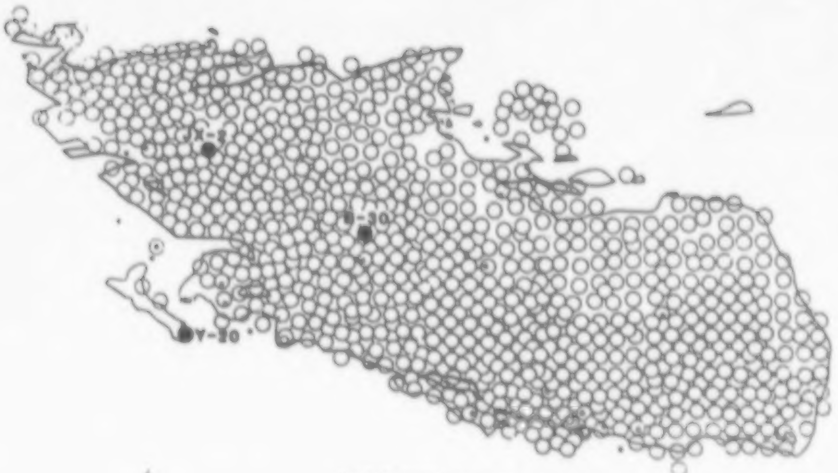

Fig. 3—Horizontal well locations.

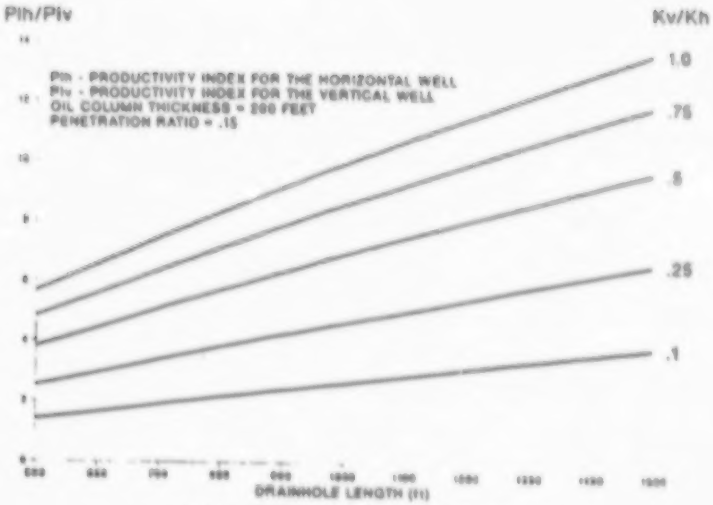

Fig. 4—Comparison of vertical well PI and horizontal well PI

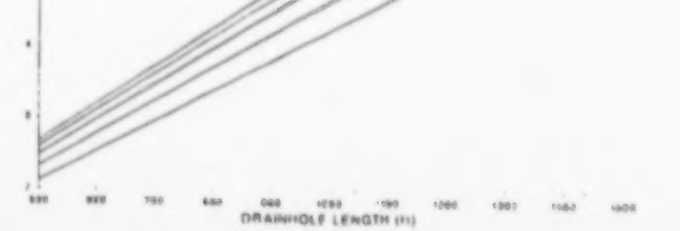

Fig. 5—Comparison of critical coning rates

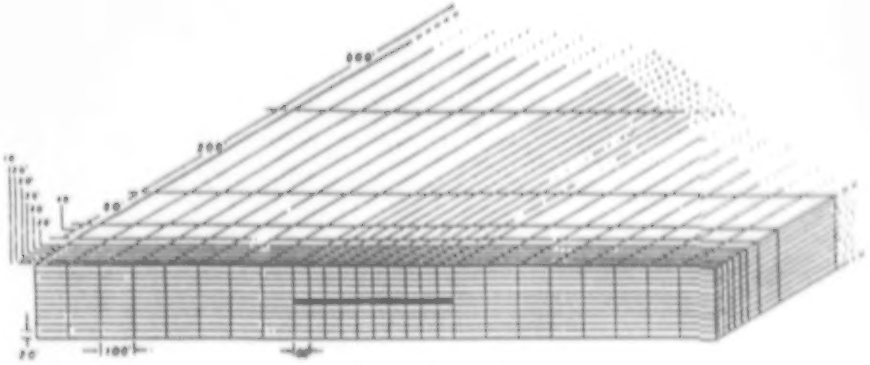

Fig. 6—Single-well model grid.

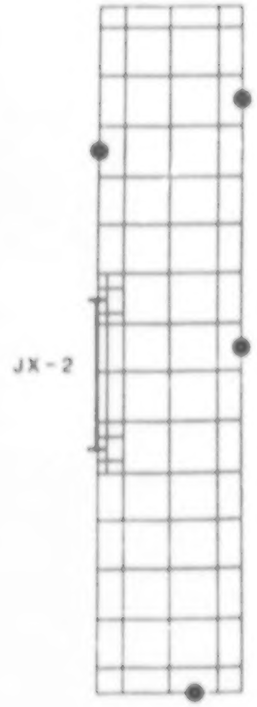

Fig. 7—Multiwell model areal grid

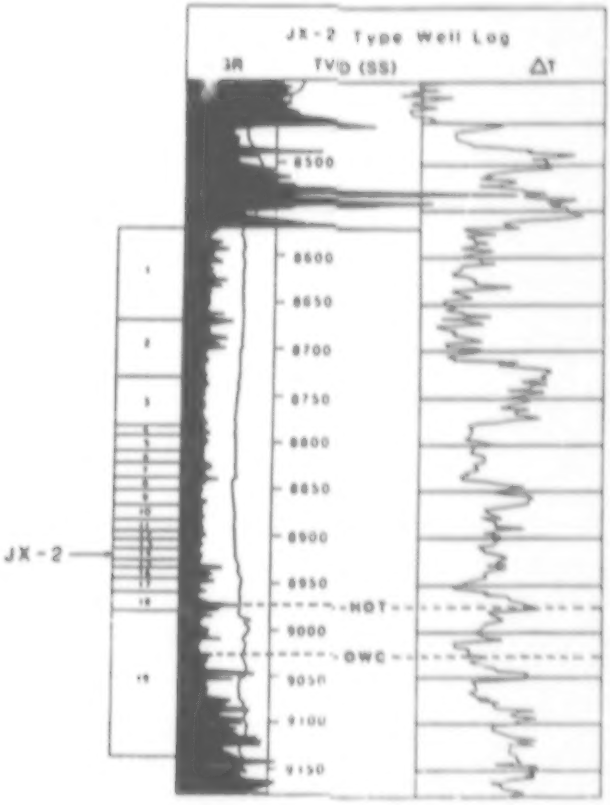

Fig. 8—Multiwell model vertical layering.

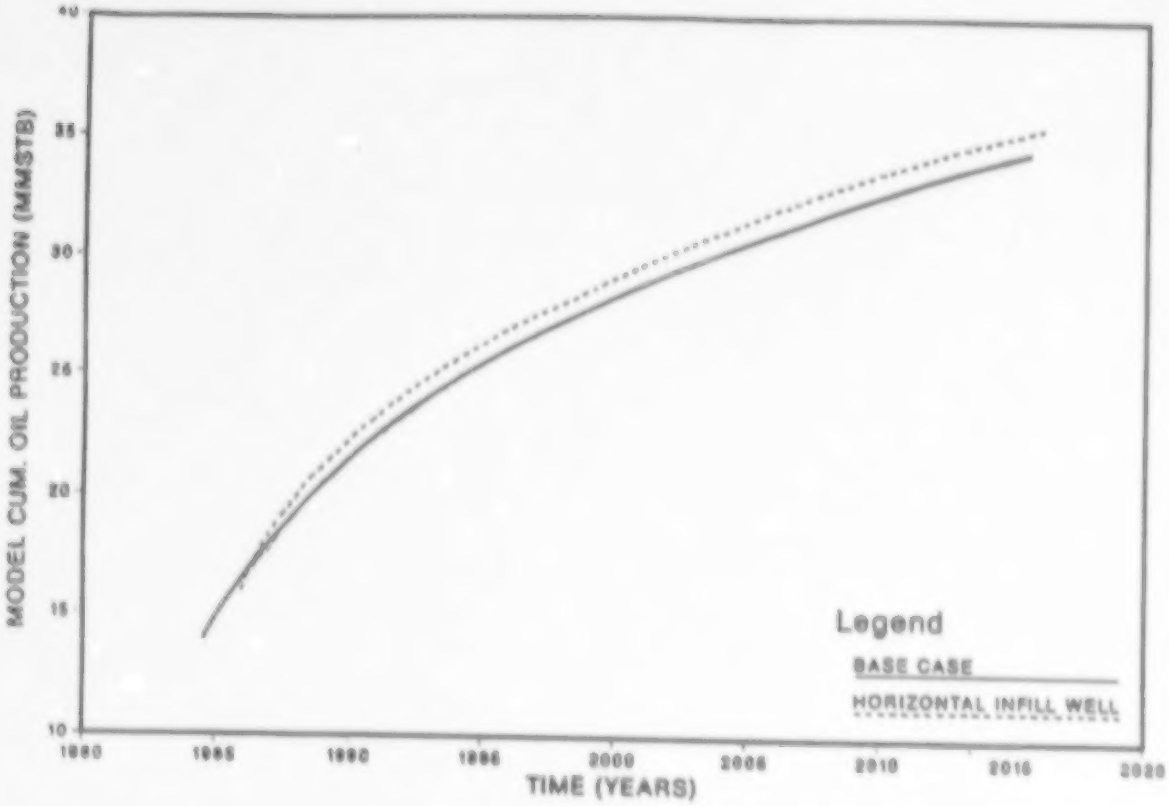

Fig. 9—Model cumulative oil production.

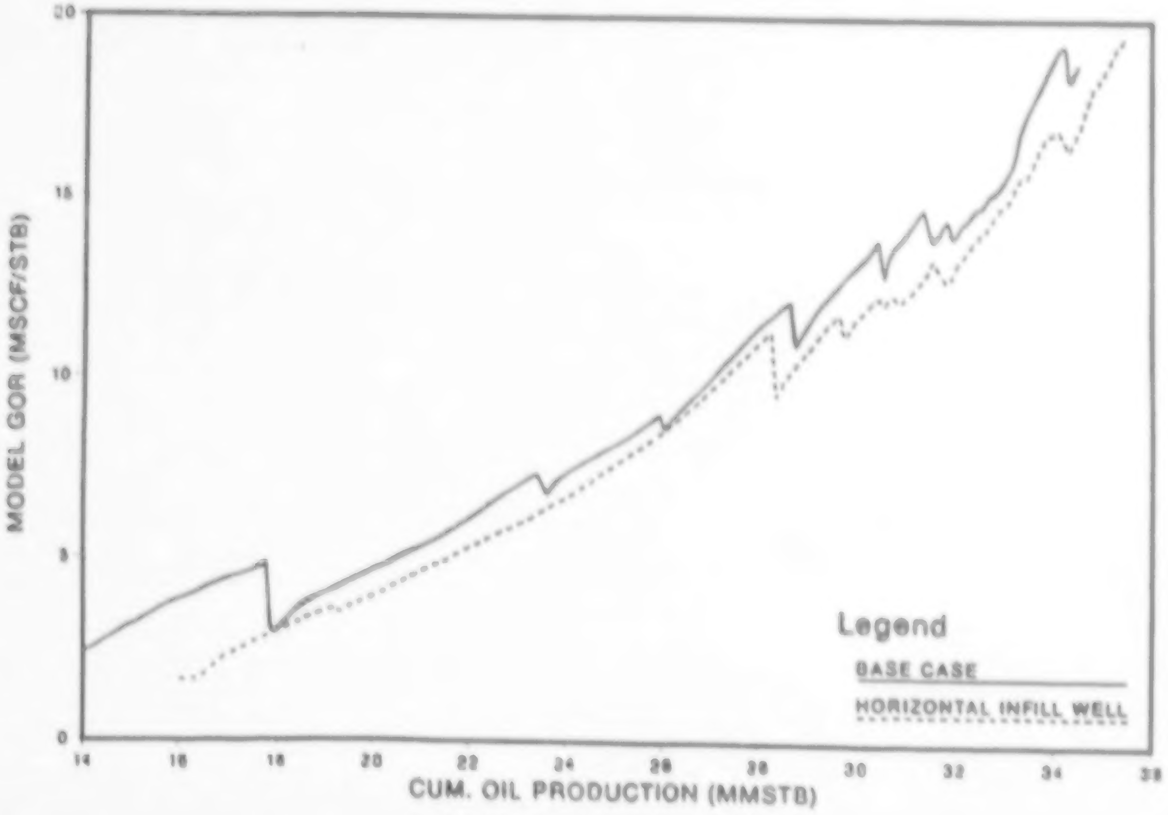

Fig. 10—Model GOR behavior.

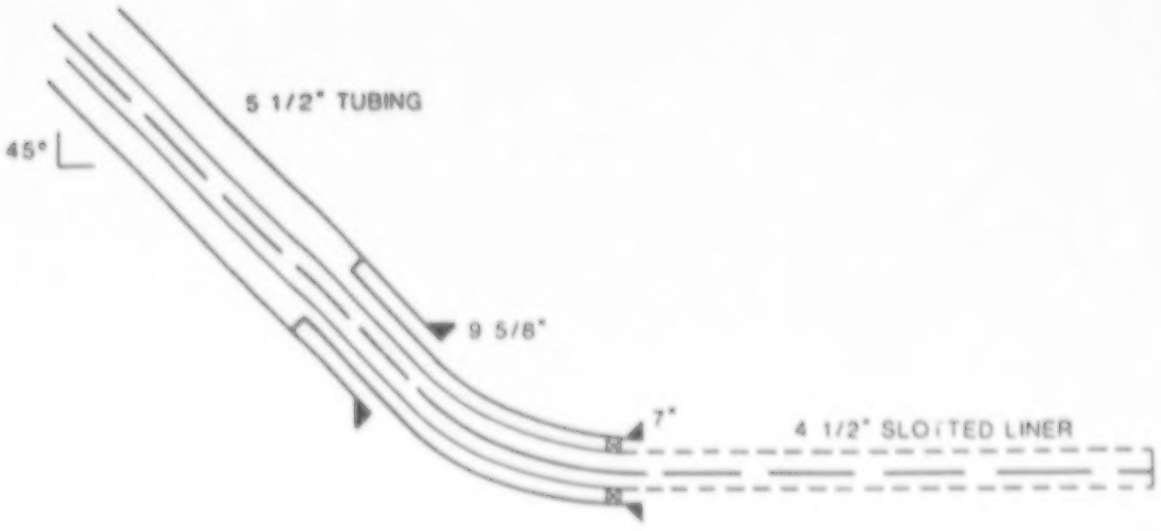

Fig. 11—Horizontal well completion.

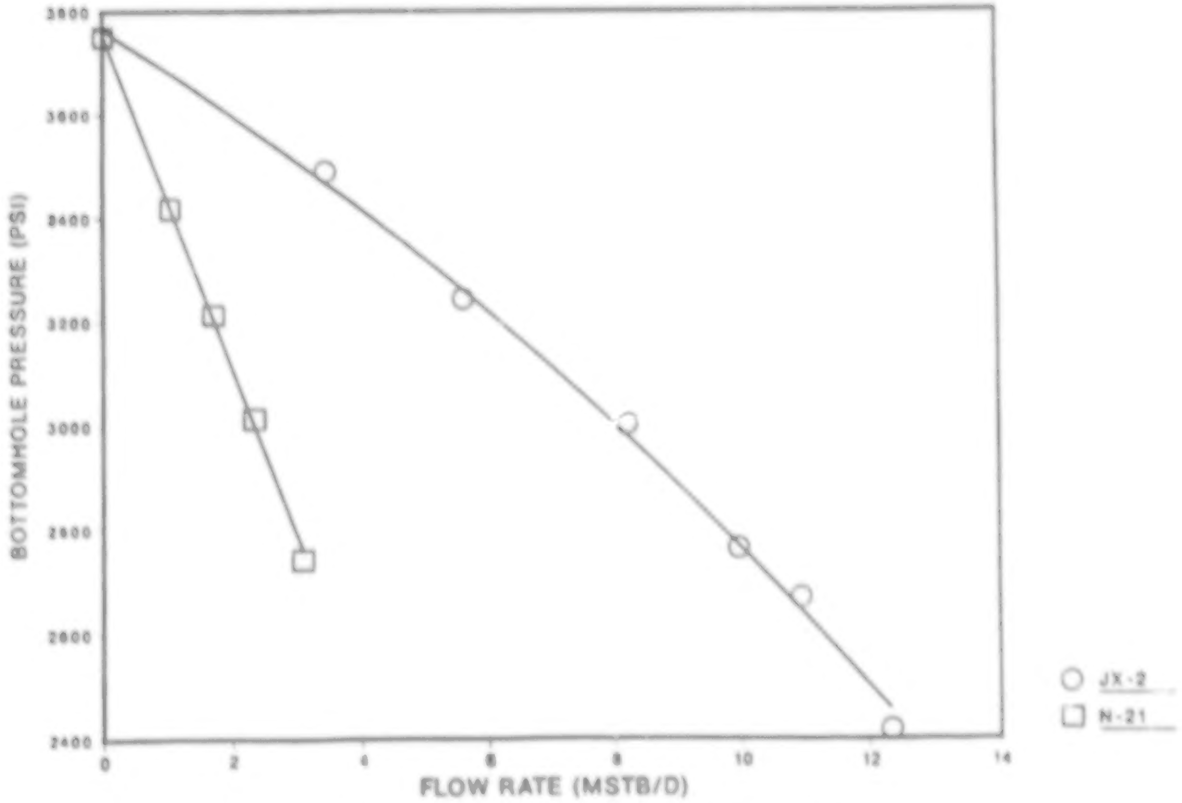

Fig. 12—Inflow performance comparison N-21 and JX-2.

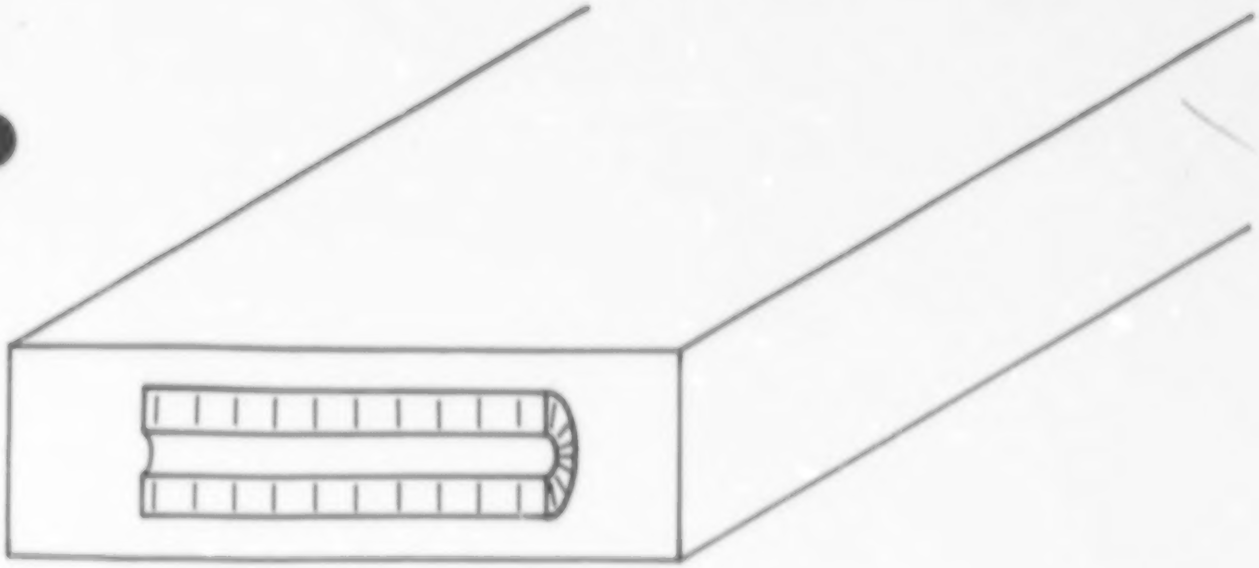

Fig. 13—Inflow performance comparison B-30 and JX-2.

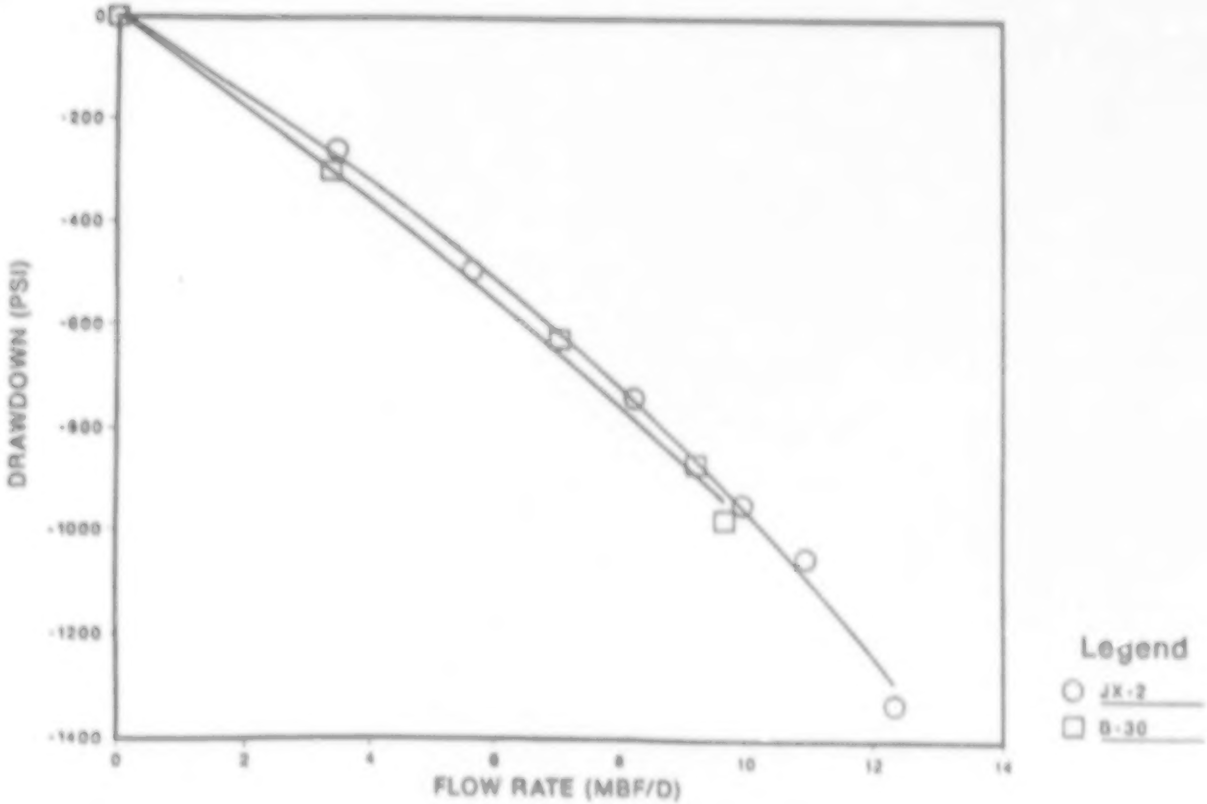

Fig. 14—Early-time radial flow.

5.4 1st Hor
4.6
3.9 - 3rd Hor
2.5 ← Conv

Future well cost
3 > 4 million

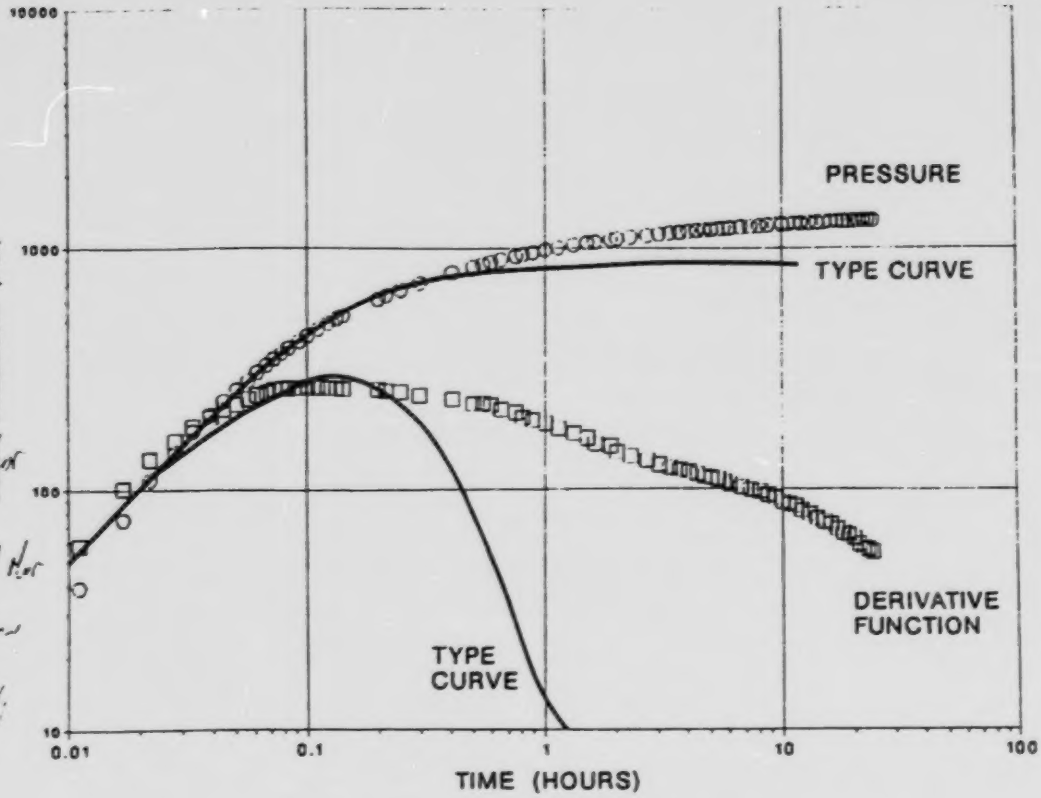

Fig. 15—JX-2 final buildup (12/31/85) after 3-day step rate test.

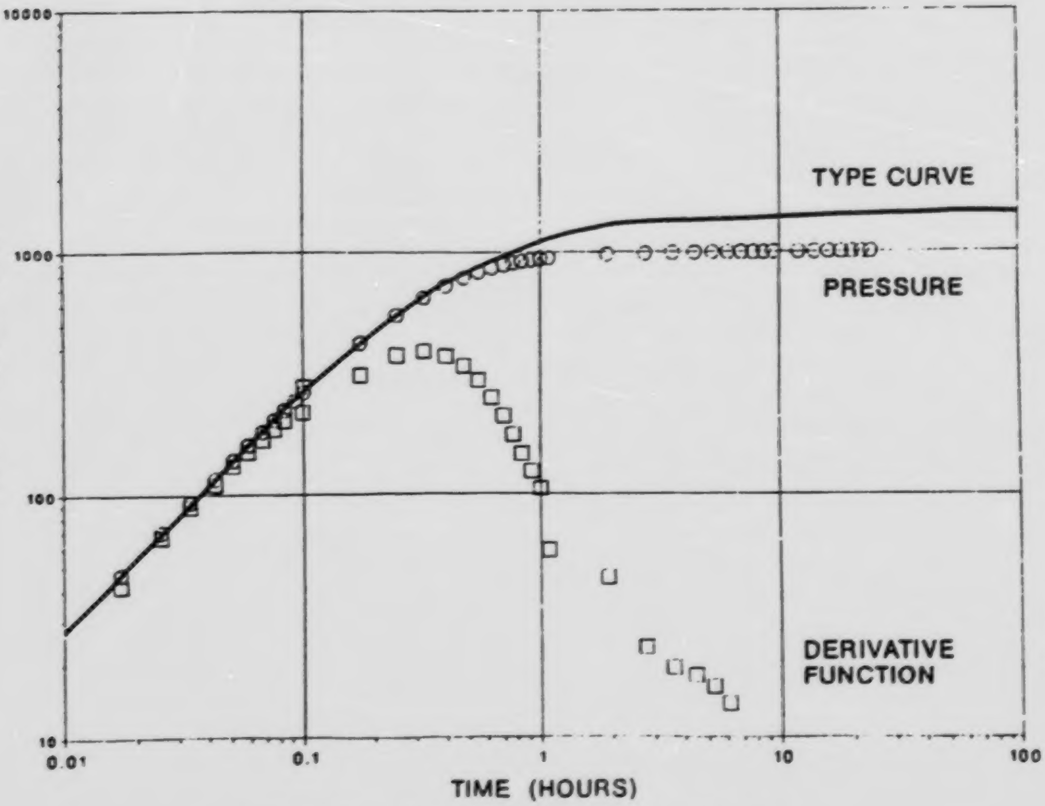

Fig. 16—N-21 final buildup (12/21/85) after 3-day step rate test.

→ target horizontal wells for areas where [illegible] OK.
[illegible]

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MINING ASSISTED RECOVERY OF PETROLEUM--CINDERELLA AT THE BALL?

Jerry E. Sinor
Consulting Associate
The Pace Consultants

The basic idea of tunneling to reach underground petroleum deposits has been around since antiquity. Many different attempts have been made in the United States in the last 120 years, but none achieved any great degree of success. Overseas operations in France, Germany, and Japan were carried on at fairly large scale for varying lifetimes. Eventually the development of modern well drilling technology made the mining approach obsolete as long as virgin petroleum reservoirs could be found easily.

Typical oil well production technology, however, will recover perhaps only one-third of the original oil in place. With conventional exploration being forced into more expensive frontier areas, the two-thirds of the oil left behind becomes an attractive target for other technologies. Most enhanced oil recovery methods will add only another 10 to 15 percent to ultimate recovery. Mining assisted approaches offer the promise of increasing the ultimate recovery percentage.

Two years ago, there appeared to be some real progress being made. The HOP Kern River process in California was expecting to receive funding from the U.S. Synthetic Fuels Corporation, Conoco's North Tisdale project in Wyoming had constructed its second production set, and Arco was said to be studying the technique for the Alaska North Slope. Since then, Ladd Petroleum has shut down the HOP project, Conoco has turned North Tisdale over to an independent operator, and Arco has disbanded its study project. It appears that mining assisted petroleum recovery is once again being treated like a neglected stepchild.

What are the prospects that this poor stepchild will turn out to be another Cinderella, and become the Belle of the Ball? I think there are some encouraging signs in this direction.

TECHNOLOGY REVIEW

The use of mining assisted methods for oil recovery is an attempt to increase well-bore exposure within an oil-producing zone at less than the cost of drilling additional wells from the surface. The economic tradeoff is relatively simple in principle. If a pay zone is 100 feet thick and lies 1,000 feet deep, then 1,100 feet of drilling of vertical wells is required for each additional 100 feet of pay zone exposure. If a mine shaft or tunnel is sunk to the pay zone, then development drilling from a mine shaft can achieve 100 percent pay zone exposure for every foot drilled. The saving of up to 90 percent in drilling footage can be balanced against the cost of the mine development and the difficulty of drilling from underground workings.

Using this simple tradeoff, mining assisted methods cannot compete with primary production from typical light oil reservoirs by conventional means. Conventional production "skims off the cream" of an oil body by taking advantage of the natural energies stored in a reservoir. This natural energy may be in the form of gas cap pressure, solution gas pressure, reservoir water drive, formation pressure, etc. When these sources of reservoir energy are missing or exhausted, and production depends solely on gravity flow to a well-bore, then oil moves through the reservoir only slowly. Increased drilling becomes necessary to capture significant quantities of oil in a reasonable time period. As the required well spacing decreases, well drilling costs approach the region of equivalence to mining assisted drilling.

A simple mining assisted technique involves sinking a vertical shaft to the pay zone, then mining out a room at the base of the shaft, from which to drill horizontal drain holes. This is basically the approach which has been used in test projects in Ohio, Texas and Wyoming. The original HOPCO approach featured steam injection as well as oil production from the horizontal spoke wells.

The next extension of the technology is to run horizontal tunnels under the oil formation and drill upward into the oil zone. This technique avoids the problems created by permeability barriers which often impede vertical flow in a reservoir. This problem appears to have been responsible for some of the relatively poor results obtained with horizontal drain holes alone.

Beyond the simple vertical shaft and horizontal tunnel concept, many conceptual schemes have been proposed, utilizing multi-level mining and varied drilling patterns.

Where simple gravity flow is ineffective, the mining assisted approach can be augmented by injection of steam or chemicals, or other EOR techniques.

STATUS OF MINING ASSISTED PROJECTS

HOP Kern River Project

Early this year Ladd Petroleum Corp. discontinued steam injection at the 25-acre HOP pilot project. Production had climbed to about 300 BPD from about 50 BPD since January 1984. Although this production level was near the break-even point for steam injection, it was only about half the rate which had been expected by that time.

Ladd then withdrew its application for aid from the U.S. Synthetic Fuels Corporation and sold the lease back to Shell Oil Co., from whom it had been obtained on a farmout. Because Ladd reserved all rights to the technology, Shell plans to convert the site to a conventional steam flood. To date, Ladd has developed no other project plans for the technology. The vertical shaft at HOP Kern River was 5 feet in diameter and about 400 feet deep.

North Tisdale Project

In 1979 Conoco developed its first oil mining project by mining a 1,000 foot horizontal adit into the side of Tisdale Mountain. Six horizontal drain holes with a total length of 6,000 feet were drilled from the end of the adit. In 1981 they developed a second production set by sinking a 235 foot vertical shaft 14 feet in diameter and drilling six horizontal drain holes from a room at the bottom, again with a total drilled length of about 6,000 feet. Initial production from each the adit and shaft was about 100 BPD but quickly declined to about 12 BPD.

In 1984 Conoco turned the operation of the North Tisdale project over to New Tech Oil Co. New Tech drove additional drifts under the oil sand, cut out nine drill stations at 100 feet intervals and then drilled upward into the reservoir. Some 16,000 feet of hole have been drilled. Further development is continuing and New Tech expects to be producing 1,000 BPD by September, 1986.

Alberta Underground Test Facility

The Alberta Oil Sands Research and Technology Authority is building a $50 million vertical shaft and underground tunnel test facility to try out various mining assisted approaches in the Athabasca tar sands. Two 10 foot I.D. shafts have been sunk some 700 feet to a limestone formation below the tar zone. Horizontal tunnels will be developed and long, inclined drain holes will be drilled upward into the tar zone for steam injection (or other techniques) and tar recovery.

Surface equipment is being put in place and underground tunnel development will continue through the winter. Drilling from the tunnels to develop drilling techniques is expected to begin in July. AOSTRA is soliciting industry participation in the test phase, and 14 potential participants are currently evaluating the processes to be used in the test phase. Drilling and initial operations for the pilot phase are expected to ocur in 1987.

Devran-Shell Canada Project

Devran Petroleum Ltd. and Shell Canada Resources Ltd. announced an agreement in 1985 to develop an abandoned oil field near Sarnia, Ontario. Devran will operate the 2-year $6.3 million project. The project design consists of a vertical shaft and 24 or more horizontal wells in a radial pattern. Hydraulic or high energy gas fracturing can be used in the wells to create production channels in the reservoir. Two levels will access two separate oil zones.

The shaft will be 400 feet deep and 9 feet in diameter. The horizontal wells will be up to 2,500 feet long in order to drain the entire 400 acre unit. Initial flow at full production is expected to be on the order of 600 BPD.

New Tech Oil Ohio Project

New Tech Oil Co. began its Ohio project in the Buck Run oil field near Malta, Ohio in 1982 by leasing a property that had first been produced in 1860. It was previously the site of an oil mining project in 1945, when a 113 foot deep shaft was sunk and two 500 foot horizontal holes drilled from the bottom. New Tech deepened the shaft to 150 feet, drove two 120 foot drifts, cut drill stations every 50 feet, and drilled 114 vertical and inclined wells. Problems with paraffin plugging limited the production which could be maintained, but on the basis of the experience gained, New Tech is preparing to develop a second project in Southeast Ohio.

Illinois Project

A private investor group in Illinois is sinking a 400 ft vertical shaft. The shaft was collared in August. Horizontal drain holes will be drilled from the bottom of the shaft in a thirteen foot pay zone.

Caddo/Pine Island

Petroleum Mining Company, Ltd. had proposed a project at Pine Island, Louisiana. Shafts would have been sunk through the tight Annona Chalk oil-bearing formation to develop a gravity drainage network. This company has apparently encountered financial difficulties, but at least two other groups are also attempting to organize similar projects in the area.

Tetra Systems/Sohio Project

Tetra Systems of Golden, Colorado had been working to develop an oil mining project in the Sistersville field, located beneath the Ohio River in West Virginia. Tetra's initial site selection proved unfortunate as the expected oil was not found on exploratory drilling. When Tetra then ran into financial difficulties the West Virginia Public Land Corp. held up signing of the lease agreement. An arrangement was then worked out with Sohio under which Tetra will retain an overriding royalty but Sohio will take over the project.

The project concept involves a vertical shaft to depths below the formation, with tunnels and upward drilling. Exploratory drilling from the surface is underway now and favorable results from reservoir modeling should lead to shaft sinking next summer. A decision is expected in Feburary or March.

Argentina

Inpro Engineering Ltd. of Edmonton, Alberta announced early this year an agreement with Yacimentos Petroliferos Fiscales, the state oil company of Argentina, to develop a chemically aided oil mine project in southern Argentina. The commercial phase of the project is said to involve a 11.5 foot diameter shaft 2,500 feet deep. After drilling horizontal wells, an alkaline/polymer flood technique would be used between wells.

The first phase of the project would be a pilot operation at a shallower depth. No current information on project status is available.

Romania

The production of oil by mining assisted extraction techniques is undergoing a significant test in Romania. Oil production from vertical and horizontal wells drilled from underground was first carried out in 1925. The Meotian reservoir of Sarata-Monteoru contains a series of inclined, thin, oil-bearing strata 0.1 to 2.5 meters thick. In 1977 an extension of an old mine was begun. From 1979 to 1984 about 1,400 meters of underground workings were developed. Beginning in 1984 a deeper horizon was opened up and both horizontal (100 meter) and vertical downward (120 meter) wells drilled from underground. In 1981 thru 1984, production averaged 252 BPD. 1985 production is expected to be 465 BPD, and a new mine is planned in 1987.

In the Runou-Bustenari area, a pilot mine is under construction involving two shafts, 3 meters in diameter and 330 meters deep. Completiion of the shaft is expected by the end of 1985. Both horizontal and ascending wells will be drilled from mining works developed from the bottoms of the shafts.

A similar project is also in the planning stages at Solont.

Naval Petroleum Reserve

The U.S. Department of Energy has been considering mining assisted in situ recovery for the U.S. Naval Petroleum Reserve in Wyoming. Early this year a study by Morrison-Knudsen was completed on the Shannon Reservoir at Teapot Dome. This reservoir has 180 million barrels of oil in place, of which 5 million have been recovered from the highly stratified and fractured reservoir. The study considered the costs of 600 foot vertical shafts, drifts, and fan drilling on a 160 acre layout. For the two vertical shafts, with a 100 foot connecting tunnel and horizontal drilling from that tunnel, total costs were estimated to be $16,000,000. A sub-level drifting case with 10,000 feet of drifting and upward fan drilling added $13,000,000 to the cost. These costs were deemed too high for immediate implementation. Consideration is being given to use of the Bechtel hydraulic drilling technique for horizontal drainholes drilled from the surface in order to evaluate the effects of horizontal drainage.

Results from these tests would then aid in estimating production rates from a mining assisted production facility.

USSR

The most extensive effort of the current era is the Yarega field in Russia. Production is on the order of 10,000 barrels per day. The mine is developed on two different levels--one above the pay zone and one at the bottom of the reservoir. In the lower workings, 80 foot diameter, doughnut-shaped work chambers are developed on 4.5 acre spacing. From each chamber about 250 production holes, 650 to 800 feet long, are drilled in a radial pattern. Steam injection wells are drilled downward from the upper mine level.

As of 1984 there were three mines encompassing 15 underground slant blocks, with 4,192 production wells and 11,795 steam injection wells. In 1984 a fourth mine was under development, starting with an 8.5 meter diameter vertical shaft 200 meters deep.

Recent production has not come up to expectations. Apparently problems have been encountered with the ventilation systems. Russia recently signed a contract with Joy Manufacturing of the United States for improved ventilation fans. Problems have also been encountered in sinking a new shaft. In spite of the problems, further developments are planned. One area under study would involve mining under the Caspian Sea.

Norway

Petromine of Norway is seriously studying an offshore application for mining assisted in situ technology. Access would be either from an island or by tunneling out from shore. A go/no go decision is expected by the end of the year.

Other

Consideration has been given to undersea projects off the Ivory Coast in Africa, and off the English cost. China is said to be interested in the technology. Projects in New Mexico, Texas and other states are in the talking stage.

THE POTENTIAL OF MINING ASSISTED RECOVERY

The bare elements of technology for mining assisted petroleum recovery are definitely available, at least for working in consolidated formations outside the oil zone. Techniques for drilling and lining vertical shafts down to at least 2,000 feet are well developed. Conventional mining practices can be used to develop tunnels from the bottom of a shaft. Drilling machinery and techniques for drilling horizontal or sloped boreholes from underground workings have been developed and used on a number of projects.

It is clear from the activities in Russia that fairly large-scale activities of this type are feasible. Why then, has little progress occurred in the United States? As with most simple questions there is no simple answer. It is possible, however, to postulate some contributing factors.

First, performance at projects such as Conoco North Tisdale, HOP Kern River and others has been disappointing. A major hazard would appear to lie with inadequate consideration of vertical permeability barriers. In a conventional oil well, with horizontal flow to the well, variations in vertical permeability are of lesser importance. It is of crucial importance in a gravity drainage analysis.

Reservoir analysis is therefore an important key to a successful project. Although the analytical tools necessary to model gravity drainage are considered to be available, small project-financed groups may not have sufficient resources to undertake the extensive reservoir analysis required to assure success. To sell an independent project to investors, it is necessary to demonstrate that the right reservoir is available. It may take a considerable expenditure to find and define this reservoir.

A second factor is the negative mind-set of major petroleum companies toward small-scale technology. Mining assisted recovery appears most applicable to small, shallow, scattered reservoirs, any one of which has a limited potential for maximum production rate. Major companies usually do not hold onto acreage of this kind, but prefer to concentrate on hunting for "elephants". Furthermore, they do not want to gamble on harming the producibility of a working field.

Within large oil companies, there appears to be a certain amount of mistrust of mining in general. This may be due to the unfavorable experience that some oil companies had in acquiring mining companies. Or it may simply be due to unfamiliarity with the technology. Mining assisted in situ technology requires both mining engineering and reservoir engineering expertise. Attempting to proceed without top-notch advice in either area could be disastrous.

An inhibiting factor for some companies has been the uncertainty over how oil mining operations would be regulated. In some states they might fall under mining regulations, in others under oil and gas regulations, and in others under both. The Mine Safety and Health Administration is promulgating specific new regulations for oil mining. These should be issued in May and will clarify MSHA's position. One way of judging the maturity of a technology is to see how many government regulations have been put in place to control it. From this standpoint, oil mining has now officially arrived.

Another negative factor has been the publication of several Department of Energy-sponsored reports which did not put mining assisted approaches in a favorable light. These reports discussed abstract technologies such as block caving which have no practical bearing on a today-and-tomorrow oil mining project. Economics were estimated by using drilling costs for drilling conventional oil wells rather than underground drilling costs in mines. Actual drilling costs, where liners are not needed, may be lower by a factor of 10 than some of the figures used in these reports. New Tech Oil Co. reports drilling rates of 300 feet per shift, at a cost of $1.50/foot. This is very similar to Russian experience at Yarega, where they note that a 2-man drill rig drills 30,000 feet per month at a cost of $1.65/foot. These costs undoubtedly do not reflect full overhead costs that would be involved in a major oil company project.

These studies have also given a misleading picture of resource availability. By focusing on very large reservoirs which could justify very large expenditures, they leave the impression that opportunities for applying mining assisted technologies are limited. However, in the United States alone there are probably several hundred reservoirs for which this technology may be suited on a small scale. The United States, in fact, is uniquely suited as a target area because of the large number of wells which have been drilled and the reservoir information which is available.

The total applicable resource depends strongly on the maximum depth which is assumed to be feasible. This could obviously go well below 2000 feet if justified by the potential resource recovery. For the time being, attention will be mostly limited to the very shallow depths of a few hundred feet. The financing requirements at these levels may be within reach of medium size independent operators.

A 200 acre reservoir with 1,000,000 barrels recoverable is large enough to be considered a target for a simple shaft-and-horizontal-drilling approach. If costs are kept under tight control and the desired recovery rate can be achieved, many projects of this type should become profitable. This should create a significant new opportunity for independent operators to redevelop abandoned fields. Cinderella will indeed get to the ball.

It must not be assumed, however, that getting to the ball will be simple. In the drilling boom of a few years ago, an independent operator needed only a landman and a geologist. It will now be necesary to have a landman, a geologist, a reservoir engineer and a mining engineer. The challenge is there for those who will accept it.

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(54)

Chapter 50

THE MINE ASSISTED IN-SITU PROJECT

P.C. Quinn and G. Duncan

Abstract

The first phase of this project is designed to test the technical feasibility of extracting bitumen from the Athabasca Oil Sands using an in-situ technique known as thermal mining. The objectives of the first phase pilot are discussed. The most significant variable of the Mine Assisted In-Situ Project is the drilling and completion of horizontal wells in the McMurray Oil Sands Formation. Various drilling techniques employed in the drilling and completing of three horizontal wells are discussed.

The Alberta oil sands deposits contain close to one trillion barrels of bitumen of which less than ten percent is considered amenable to recovery by surface-mining methods. Under current circumstances, overburden thicknesses in excess of 150 feet (depending on grade and sand thickness) generally preclude surface mining.

The Mine Assisted In-Situ Technique is directed towards recovering bitumen from the vast bulk of the oil sands deposits that appear to be accessible only through in-situ methods. The technique conceptually combines shaft and tunnel mining, drilling of wells for purposes of steam injection and oil production, underground separation of bitumen, oil, gas and produced solids, and the pumping of recovered bitumen to the surface for upgrading, transportation, and refining to synthetic crude oil. (Figure 50-1).

If technical and economic feasibility can be demonstrated, then the Mine Assisted In-Situ Technique could open the way for the commercial production of an energy resource which may not be developed because of excessive overburden thicknesses. The Mine Assisted In-Situ Project is the first phase of a program designed to test the technical feasibility of extracting bitumen from these oil sands using an in-situ technique known as Thermal Mining. Thermal Mining differs from other in-situ methods in that the wells are drilled and completed *not* from the surface, but from an underground excavation, eliminating the need to drill each well through the overburden.

Early in 1977 a preliminary study examined the technical and economic feasibility of applying the mine assisted in-situ techniques to the Athabasca oil sands.

A mine layout was developed (Figure 50-2) which consists of 3 shafts located approximately in the center of the area to be mined, combined with three main and two production tunnels located 50 ft below the oil sands, in the Devonian limestone. Each production cell is approximately 1,500 ft wide by 4,000 ft long.

Based on this mine layout two different cases were investigated: Case (A)-A High Density Drilling Pattern, and Case B-A Low Density Drilling Pattern, from underground tunnels, as shown in Figures 50-3 and 50-4.

The High Density drilling scheme has a well spacing of approximately 15 ft between wells and the Low Density scheme has a 100 ft well spacing.

Table 50-1 summarizes and compares the results of the two schemes.

One of the significant variables in this technique is the drilling and completion of horizontal holes in the McMurray formation.

Petro-Canada is acting as operator for a five party consortium, consisting of Canada-Cities Service Ltd., Gulf Oil Canada Resource Inc., Husky Oil Operations Ltd., Esso Resources Canada Ltd., and Petro-Canada Exploration Inc., which is investigating the feasibility of horizontal drilling and completion through a surface demonstration test at an outcrop site in the Athabasca River Valley.

The overall objectives of the surface demonstration are to increase confidence in proceeding to an underground test and to obtain data to aid in the design of an underground test.

In order to achieve these objectives the following program was developed:

1. All drilling will be done on a 4° angle to the horizontal. Drill a 266 mm hole 6 m long and cement in 244 mm conductor pipe. Drill a 219 mm hole, 220 m long in the limestone and cement in a 168 mm surface casing. Drill out of the surface casing and into oil sand a distance of 487 m with a 149 mm bit. Complete the well with 330 m of

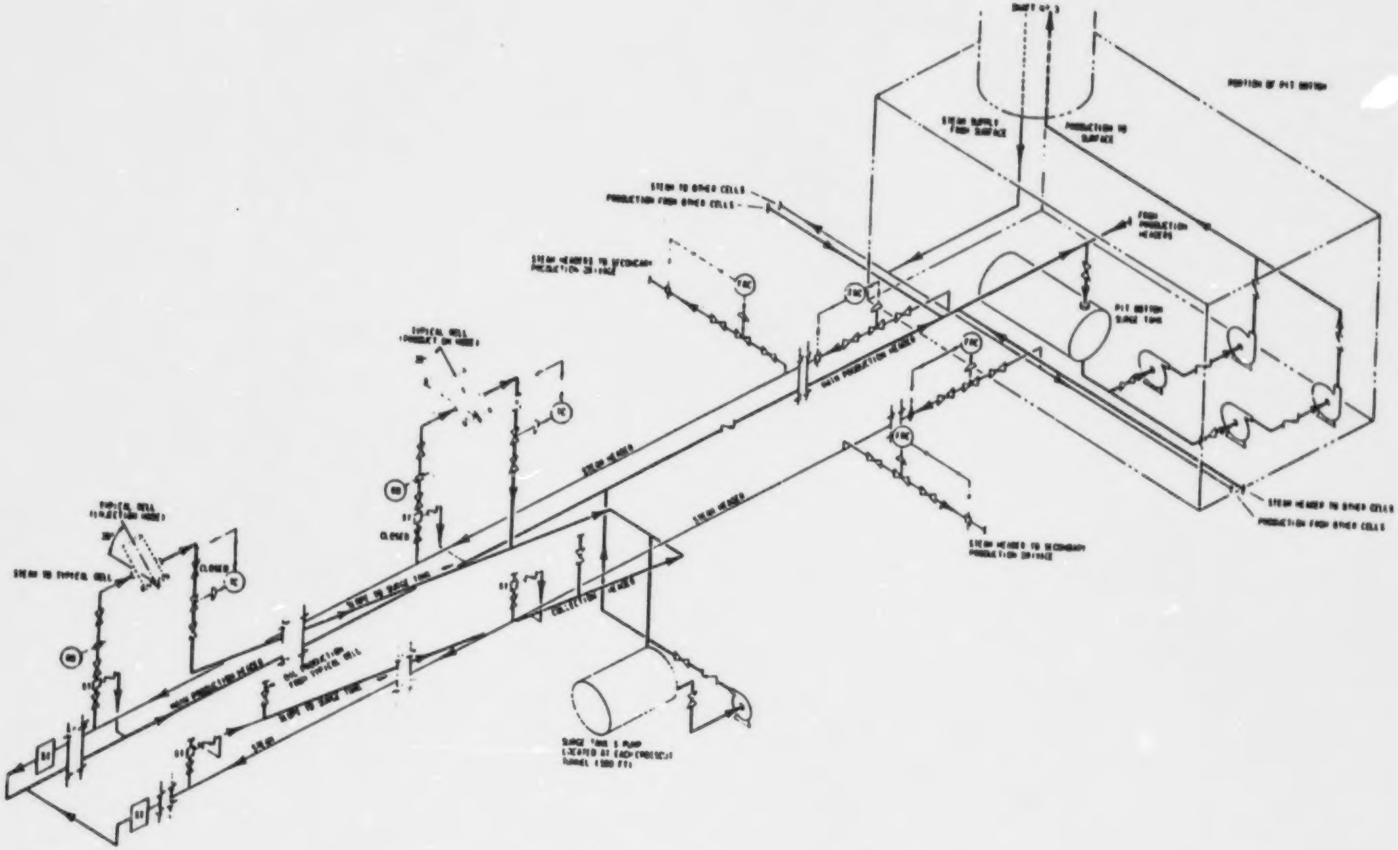
SHAFT NO. 3
PORTION OF PIT BOTTOM
STEAM SUPPLY FROM SURFACE
PRODUCTION TO SURFACE
STEAM TO OTHER CELLS
PRODUCTION FROM OTHER CELLS
FROM PRODUCTION HEADERS
PIT BOTTOM SURGE TANK
STEAM HEADERS TO SECONDARY PRODUCTION DRIVAGE
MAIN PRODUCTION HEADER
STEAM HEADER
STEAM HEADER TO OTHER CELLS
PRODUCTION FROM OTHER CELLS
TYPICAL WELL (PRODUCT ON MODE)
TYPICAL WELL (INJECTION MODE)
STEAM TO TYPICAL WELL
CLOSED
SLOPE TO SURGE TANK
COLLECTION HEADER
OIL PRODUCTION FROM TYPICAL WELL
STEAM
SURGE TANK & PUMP LOCATED AT EACH CROSSCUT TUNNEL (500 FT)
FRC
TC

Figure 50.1 Typical piping isometric for a single cell

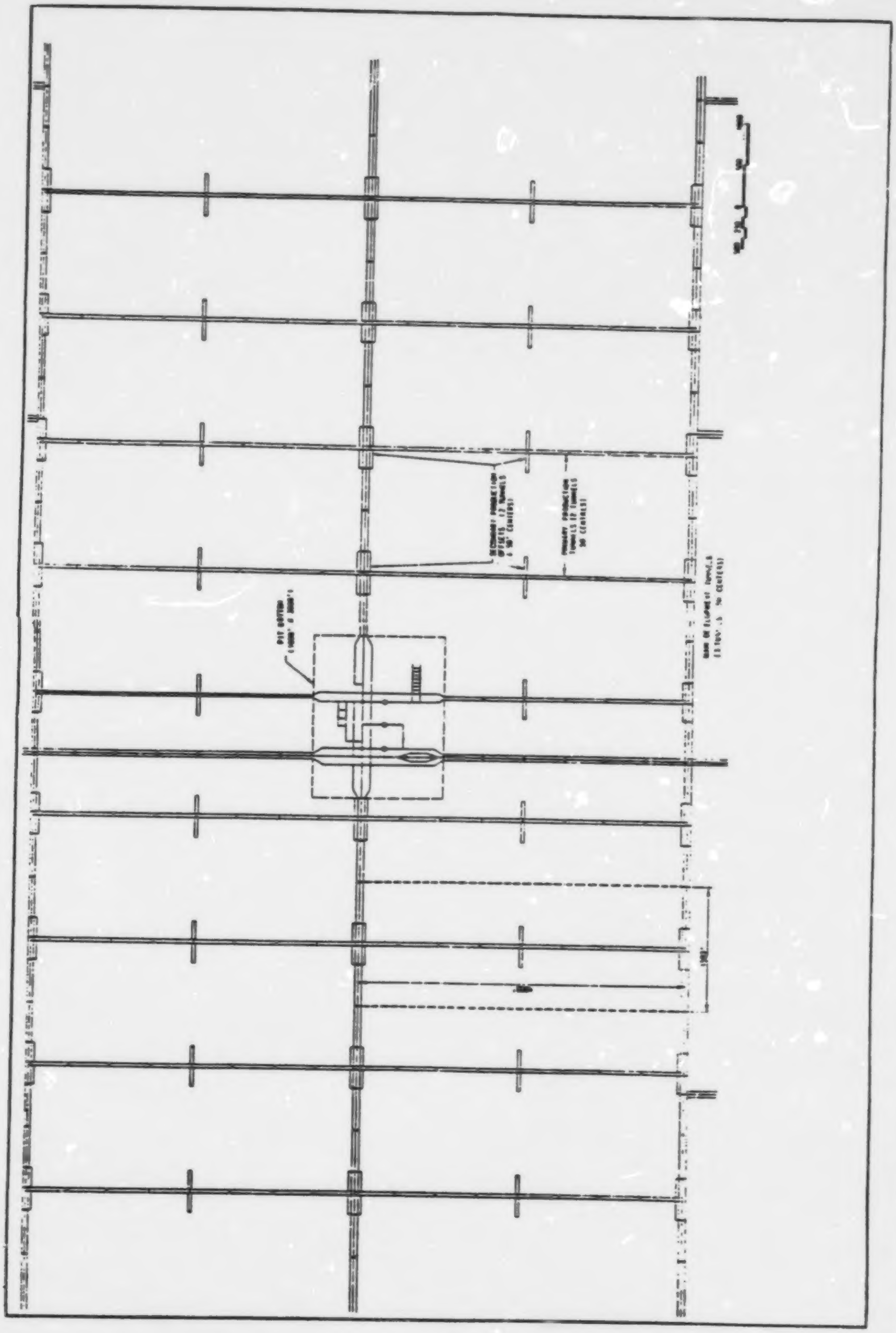

Figure 50.2 Mine layout; three main and two production tunnels

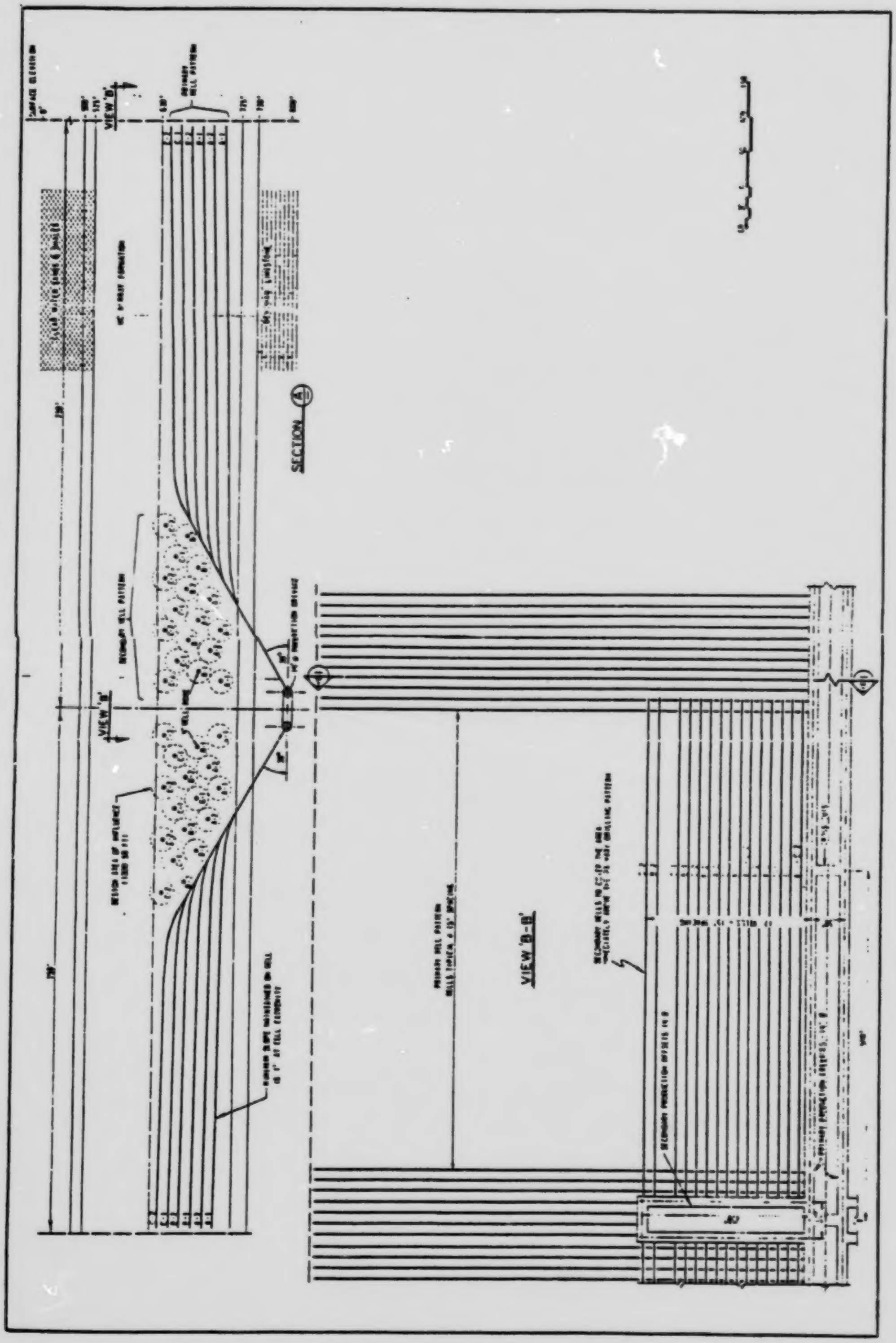

Figure 50.3 High density drilling pattern

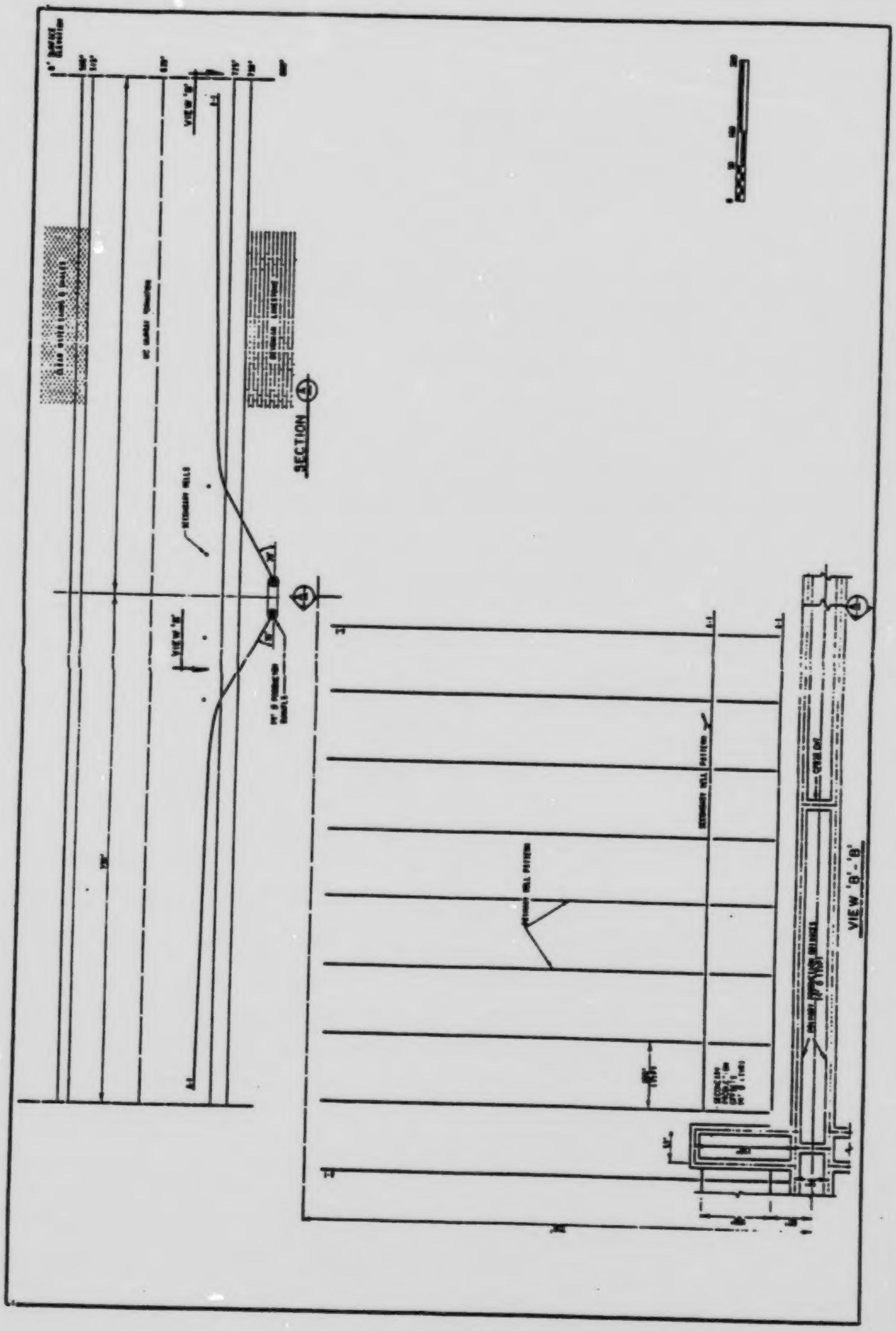

Figure 50.4. Low density drilling pattern

Table 50-1. *Summary of Design Criteria.*

	Case A	Case B
Net Bitumen Production—BPD	100000	100000
Gross Bitumen Production—BPD	122280	152800
Oil In Place—MB/Acre	300	300
Steam/Oil Ratio	2/1	4/1
Recovery—%	45	30
Cell Life—Years	5	10
Production/Cell—BPD	10190	3400
Cells on Production	12	45
Replacement Cells/Year	2.4	4.5
Drilling/Cell—M Feet	610	75
Tunneling/Cell—M Feet	16	16
Cost of Bitumen*—$/BBL	5.03	6.06

*Note: 1976 Dollars

114 mm casing, the oil sand interval to be slotted, and with 330 m of 48 mm tubing inside the 114 mm casing;

2. Drill two identical wells to a total distance of 330 m and complete the wells to 330 m;

3. Steam Stimulate all three wells; and

4. If heat connection can be achieved in a reasonable time, convert to an inter-well flood.

Design engineering on the project commenced in September, 1978. The Energy Resources Conservation Board of Alberta approved the application to construct and operate the facility on November 16, 1978. Site preparation started at Lower Mildred Lake on November 20, 1978 and was completed on March 30, 1979. The drilling operations commenced on April 17, 1979.

The following drilling methods were experimented with:

1. Sonic drilling without mud circulation;
2. Sonic drilling with mud circulation; and
3. Journal Bearing Techniques with Longyear power head and mud circulation.

The steam injection phase of the project will evaluate the following:

1. Effects of thermal expansion on the casing;
2. Movement of the well bore during production;
3. Success of the High Temperature Cement used;
4. Amount of sanding in the well;
5. Extent of heat dispersion and the thermal characteristics of the oil sand;
6. Time requirements of each cycle of the initial production-injection scheme; and
7. Initial production-injection rates and volumes.

Construction of the steam injection and produced bitumen handling and storage facilities are in progress in 1979. Start-up of the steam injection phase is scheduled for August, 1979, and the plant will operate for a one year period.

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Exploration for Heavy Crude Oil and Bitumen
AAPG Research Conference

October 28-November 2, 1984
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conducted in cooperation with the

UNITAR/UNDP Information Centre
for Heavy Crude and Tar Sands

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Robert L. Johnston, AAPG (Field Trip)

THE MINE ASSISTED IN SITU PROJECT

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JULY, 1984

ACKNOWLEDGEMENT

The author wishes to thank Canadian Occidental Petroleum Ltd., Esso Resources Canada Limited, Gulf Canada Resources Inc., Husky Oil Operations Ltd. and Petro-Canada Inc. for permission to publish this paper.

ABSTRACT

THE MINE ASSISTED IN SITU PILOT PROJECT (MAISP)

In 1978 Petro-Canada, as operator for a five party group including Esso Resources, Husky, Canada-Cities Service (now Canadian Occidental) and Gulf Canada initiated the MAISP project at an outcrop near Fort McMurray. Three horizontal wells were drilled and completed in the oil sands. The wells were successfully steam stimulated over a period of one and one half years.

This paper will review the history of the project, summarize the accomplishments and give some general comments on future application of the results.

THE MINE ASSISTED IN SITU PROJECT

Mine assisted in situ recovery is a combination of mining and horizontal wells for the in situ recovery of bitumen from oil sands. The shafts and tunnels of the mine provide access for drilling the wells rather than a direct means of recovering the oil sand. Thus the wells are drilled from an underground excavation rather than from the surface, eliminating the need to drill each well through the overburden and allowing the use of horizontal wells without the need for deviated drilling, see Figure 1.

Early in 1977 a preliminary study was conducted to evaluate the technical and economic feasibility of applying Mine Assisted In Situ techniques to the Athabasca Oil Sands.

A mine layout was developed and two different cases were investigated: Case (A) - A high density drilling pattern and Case (B) - A low density drilling pattern, from underground tunnels. Based on the favorable results of the study, plans were made to investigate the process further in the field.

One of the significant variables in this technique is the drilling and completion of horizontal wells in the McMurray formation. Plans for an outcrop test were presented at the First International Conference on Heavy Crude and Tar Sands sponsored by UNITAR and held in Edmonton in 1979. This paper will present a synopsis of the results of the project.

The Mine Assisted In Situ Project was conducted by a five party consortium consisting of Husky Oil Operations Ltd., Esso Resources Canada Ltd., Gulf Canada Resources Inc., Canada-Cities Service Ltd., (now Canadian Occidental) and Petro-Canada.

Petro-Canada acted as operator for the consortium to investigate the feasibility of horizontal drilling and completion through a surface demonstration test at an outcrop site in the Athabasca River Valley, see Figure 2.

The overall objectives of the surface demonstration were:

I. To increase confidence in proceeding to an underground test.

II. To obtain data to aid in the design of an underground test.

In order to achieve these objectives the following program was developed:

I. All drilling will be done on an angle 4° up from horizontal. Drill a 266 mm hole 6 m long and cement in 244 mm conductor pipe. Drill a 219 mm hole, 220 m long in the limestone and cement in a 168 mm surface casing. Drill out of the surface casing and into oilsand a distance of 487 m with a 149 mm bit. Complete the well with 330 m of 114 mm casing, the oilsand interval to be slotted, and with 330 m of 48 mm tubing inside the 114 mm casing.

II. Drill two identical wells to a total distance of 330 m and complete the wells to 330 m.

III. Steam stimulate all three wells.

IV. If heat connection can be achieved in a reasonable time, convert to an inter-well flood.

Design engineering on the project commenced in September 1978. The Energy Resources Conservation Board of Alberta approved the application to construct and operate the facility on November 16, 1978. Site preparation started at lower Mildred Lake on November 20, 1978 and was completed on March 30, 1979. The drilling operations commenced on April 17, 1979.

The following drilling methods were experimented with:

(A) Rotary drilling with journal bearing stabilization

(B) Sonic drilling with and without mud circulation

(C) Hammer drilling

Various circulation systems were also evaluated.

The three wells were all initiated at an an angle of 9° decreasing to 1 to 2° at 200 m. One well was drilled to 543 m total length with the other two to 330 m. Some problems were encountered with loss of circulation on cementing and with hole sloughing but these were successfully overcome. The only major problem encountered in the drilling phase was surveying the horizontal wells. The available gyroscopic tools were not designed for horizontal use and the proximity of completed wells interferred with magnetic tools. Five vertical observation wells were also drilled to monitor temperature and pressure during the steam injection phase, see Figure 3.

The steam injection phase of the project was designed to evaluate the following:

(A) Effects of thermal expansion on the casing

(B) Movement of the wellbore during production

(C) Success of the high temperature cement used

(D) Amount of sanding in the well

(E) Extent of heat dispersion and the thermal characteristics of the oil sand

(F) Time requirements of each cycle of the initial production - injection scheme

(G) Initial production - injection rates and volumes

Two modes of steam operation were tested, hot-finger stimulation and steam drive. The first mode involved injecting steam into the tubing and removing the condensate from the annulus or vice versa. When interwell communication was achieved, the operation was switched to inter-well steam drive.

Steam circulation was initiated in well H-3 in November, 1979 and in wells H-1 and H-2 in January, 1980. Interwell communication was achieved between wells H-1 and H-2 in February 1980. Communication with well H-3 was not achieved until late in 1980. Injection/production operations were continued until March 1981.

During the life of the pilot some 14 000 m^3 water equivalent of 800 kPa, 170 °C, 80% quality steam were injected into the 3 horizontal wells. A total of 850 m^3 of bitumen were produced. Although this is a steam/oil ratio of 16 tc 1, it was considered quite encouraging in view of the low steam temperature and the long pre-heating time for well H-3.

No major operating problems were encountered with the wells during the operating phase of the project.

In July 1980, a computer simulation study was initiated with the objective of understanding the recovery process and modelling the communication between wells H-1 and H-2. This study concentrated on the events occurring during the February - June, 1980 operating period. A modified version of Intercomp's Combustion Model in three dimensions was used. A history match of the field performance was achieved.

Another interesting aspect of the MAIS Project was the monitoring of the steam zone. An interwell electromagnetic survey was run in the observation wells before and after steaming. Temperature was monitored in six observation wells during the operation of the horizonetal wells. Following completion of the operating phase, nine additional wells were drilled, two were cored, carbon-oxygen logs were run in seven and all were temperature logged. The data from the various sources proved to be complimentary and together gave a very good picture of the size and shape of the steam zone.

In conclusion, the MAIS Project demonstrated that long, horizontal wells could be successfully, drilled, completed and operated in the oil sands. Although production was a secondary objective of the project, the results were also most encouraging. The next stage of development is to test the concept utilizing a shaft and a tunnel. The initial capital requirements for this are quite high and unfortunately the timing for such a test corresponded with the downturn in the economy so MAISP 2 was put on hold. Interest in a test remains strong, however. Earlier this year the Alberta Oil Sands Technology and Research Authority announced plans for a $50 million shaft and tunnel project in the Athabasca Oil Sands west of Fort McMurray AOSTRA are currently seeking industry participation in one or more recovery process tests utilizing the shaft and tunnels.

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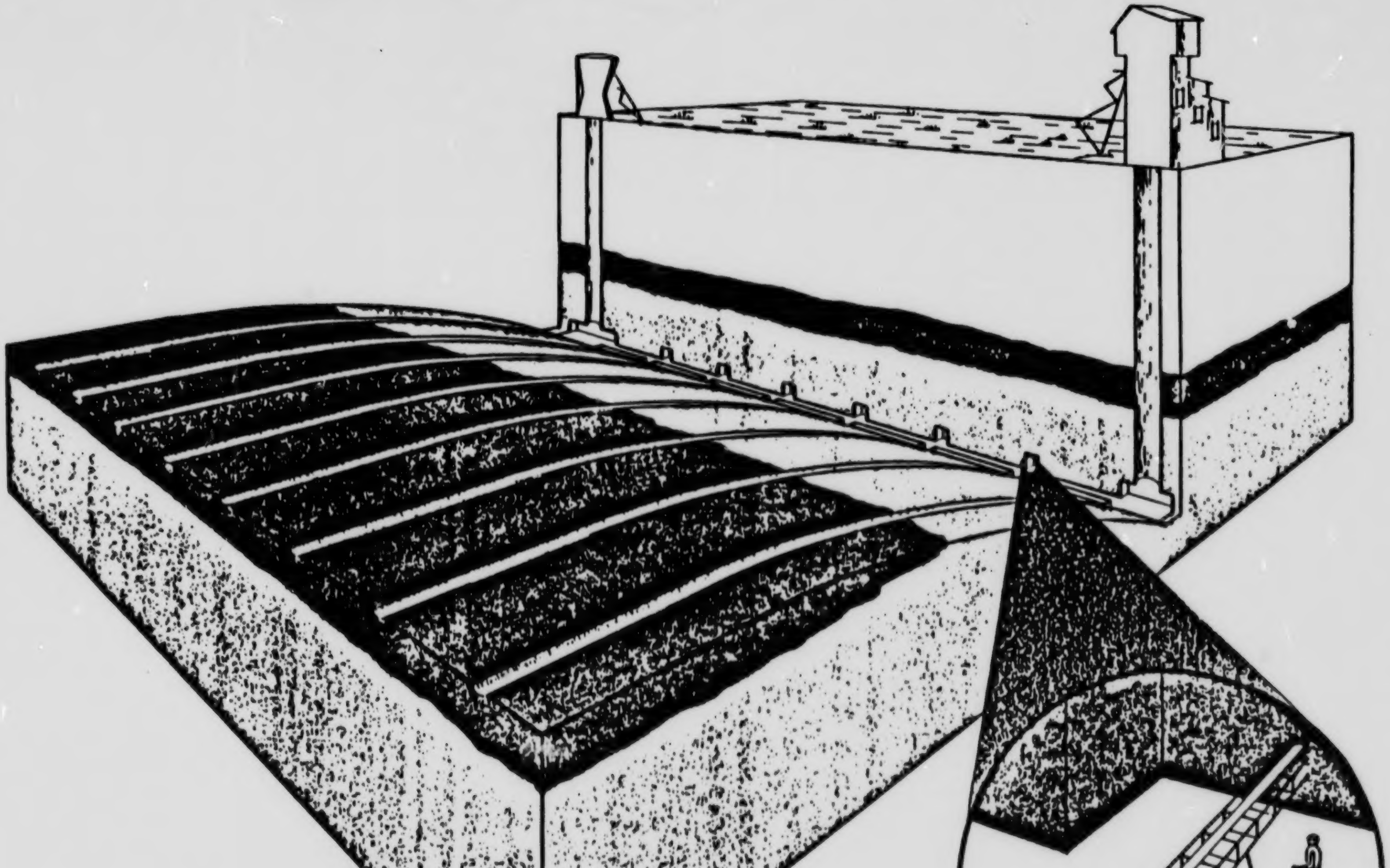

FIGURE 1
MAISP COMMERCIAL APPLICATION

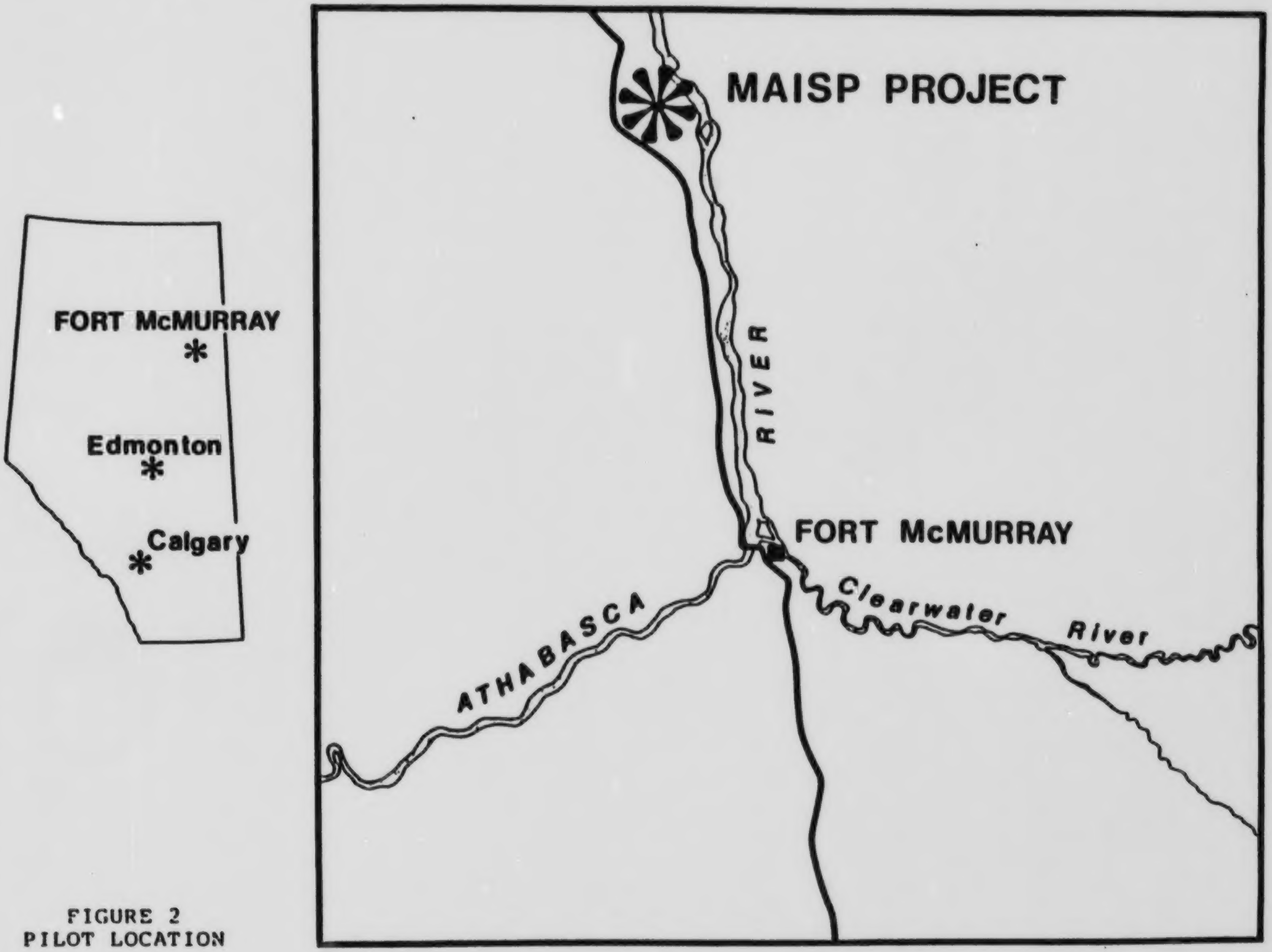

FIGURE 2
PILOT LOCATION

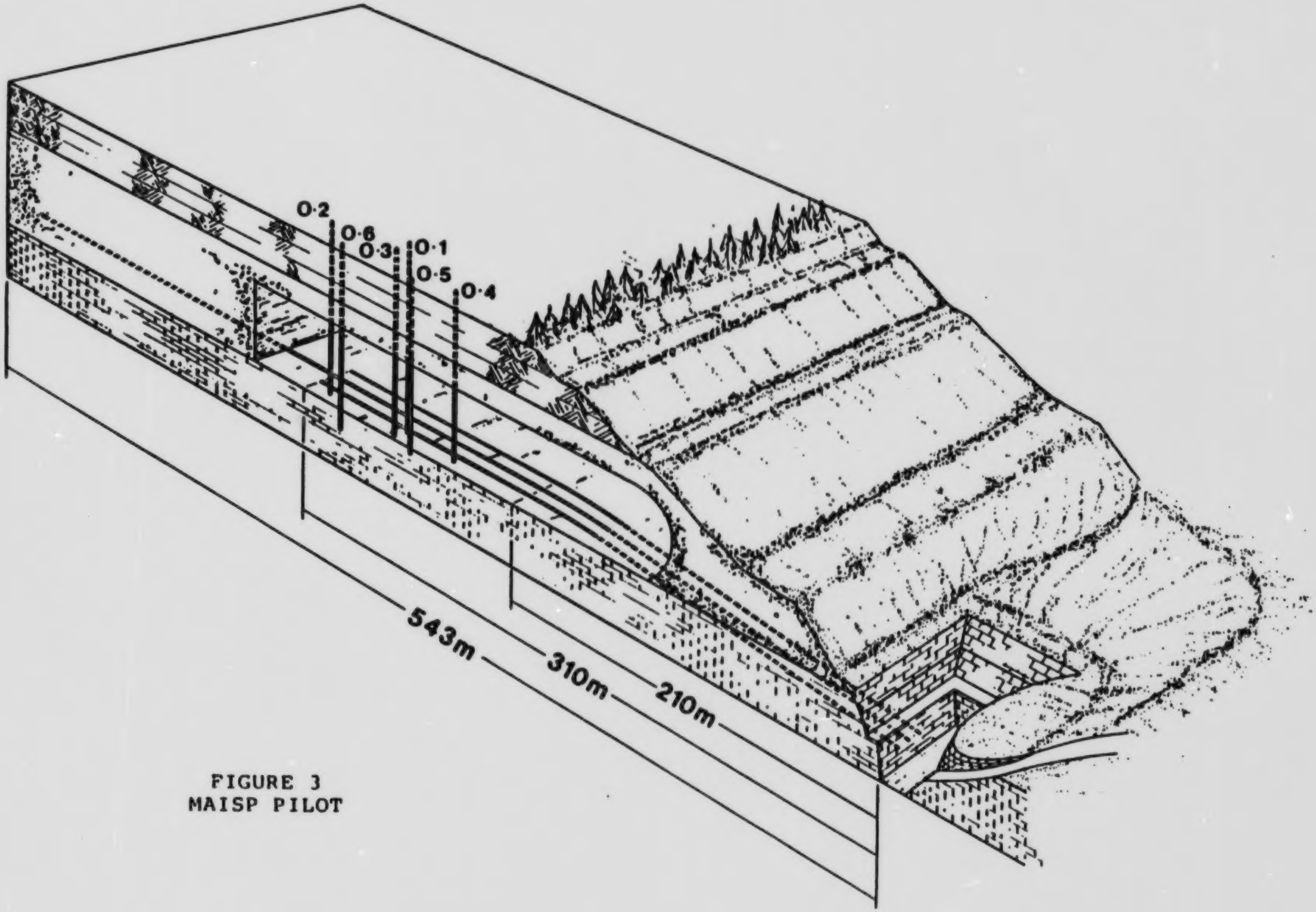

FIGURE 3
MAISP PILOT

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Session 1
Paper 4

(56)

THE MINE ASSISTED IN SITU PROJECT

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Presented at the fifth annual
"Advances in Petroleum Recovery & Upgrading
Technology" Conference

June 14 & 15, 1984
Calgary, Alberta, Canada

THE MINE ASSISTED IN SITU PROJECT

The Mine Assisted In Situ Project was conducted by a five party consortium consisting of Husky Oil Operations Ltd., Esso Resources Canada Ltd., Gulf Canada Resources Inc., Canada-Cities Service Ltd., (now Canadian Occidental) and Petro-Canada.

The first phase of this program was designed to test the technical feasibility of extracting bitumen from the Athabasca Oil Sands using an in situ technique known as Mine Assisted In Situ Recovery. Mine Assisted In Situ Recovery differs from other in situ methods in that the wells are drilled and completed not from the surface, but from an underground excavation, eliminating the need to drill each well through the overburden.

Early in 1977 a preliminary study was conducted to evaluate the technical and economic feasibility of applying the Mine Assisted In Situ techniques to the Athabasca Oil Sands.

A mine layout was developed and two different cases were investigated: Case (A) - A high density drilling pattern, and Case (B) - A low density drilling pattern, from underground tunnels. Based on the favorable results of the study, plans were made to investigate the process further in the field.

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AOSTRA

(57)

SESSION 1

INTRODUCTION

MINING ACCESS FOR PETROLEUM RECOVERY

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"Mining Access for Petroleum Recovery"

By: J.A. Haston

This morning's session, "Underground Mining and Access", concerns itself mainly with the use of technology from the mining industry to enhance the historical petroleum engineering operations of recovering oil from an underground reservoir. We will not be addressing extractive mining schemes, either surface or underground, although much of the technology could be pertinent to underground mining of oil sand for surface treatment. In mining access schemes, the mining engineer provides for operations in close proximity to a target reservoir; the key technology in the actual recovery operation is still petroleum engineering.

Mining access has been of interest to petroleum engineers for well over a century, starting with trials in Ohio and California in the 1860's. Active production in France and Germany during the 1920's sparked renewed interest in the U.S., and test operations were carried out at several locations over a period of some 20 years to about 1945. Depleting resources and increasing crude prices have again renewed interest in mining access technology, and at least three pilot schemes have been put in operation in the U.S. in the last few years.

Mining access operations have been employed in the Romanian petroleum industry since 1925. Our lead-off paper in this morning's session will summarize their experience with this technology.

The essential objective of mining access has been to provide for improved gravity drainage of the reservoir. This mechanism can be attractive in conventional oil fields where other drives do not exist or have been depleted. It could be of critical importance in the production of heavy oils where more standard pressure drives frequently result in early breakthrough and consequent poor conformity in the drive sweep.

The Alberta Oil Sands Technology and Research Authority has actively supported the development of mining access technology for almost ten years, starting with the original MAISP study which looked at adapting some Russian thermal mining experience to an Athabasca application. Recently, the Authority has taken a major initiative in this field through its commitment to put in place an Underground Test Facility (UTF) north of Fort McMurray. This facility will generate important hard data on mining access design and, in cooperative use with industry, should provide for effective field piloting of recovery processes which can take advantage of the improved opportunity for horizontal well drainage patterns. Several of the papers at this morning's session are related to this UTF project.

The overall layout of the Underground Test Facility is shown on this slide.

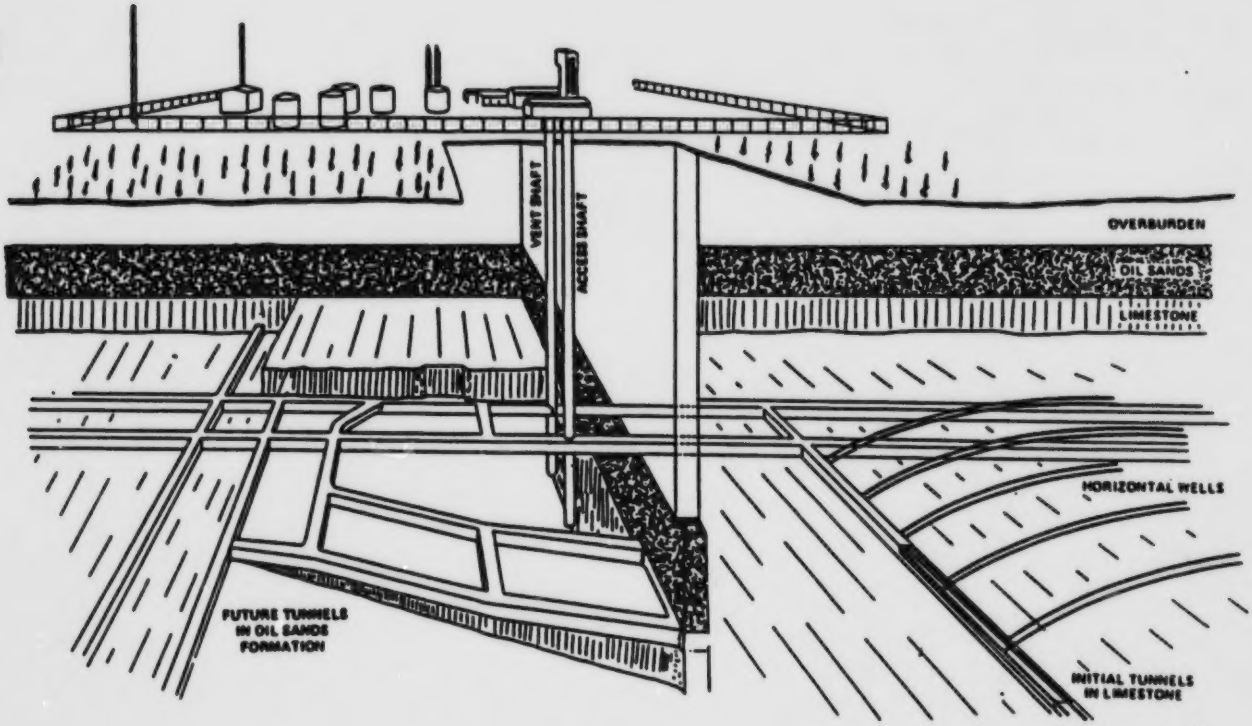
The surface plant, consisting of mine servicing, steam generation and process treatment facilities, will be located on about nine ha of cleared site on Crown land set aside for this project some fifteen kilometers west of the Syncrude plant.

Two main shafts, just over three meters in diameter, will be sunk through the McMurray formation to the underlying Devonian limestone. A system of tunnels driven through the limestone will provide access for drilling injection and/or production wells up into the McMurray formation. As well, it is expected that an experimental tunnel will be driven in the oil sands for specific research into in situ geotechnical and reservoir characteristics of the McMurray formation. This would provide the first ever opportunity to observe in situ oil sands at depth.

The AOSTRA program also includes the development of custom drilling systems to place horizontal wells from the mine environment. Compactness, pressure maintenance and directional control will require novel solutions which will be of value in many mine access applications. The end objective, of course, is the development and demonstration of efficient horizontal well recovery processes.

The UTF project is now in the field and progressing on schedule. The first shaft is in place and drilling is well along on the second one. Mine opening and field testing of the drilling system will be completed in 1986, and process pilot operations should start early in 1987. AOSTRA's project team is working closely with an industry steering committee at this time in identifying the preferred processes and scope of the pilot operations.

AOSTRA's approach to mining access has been named the Shaft and Tunnel Access Concept (SATAC). The program is justified as a promising prospect for developing some of the hitherto intractable oil sands, but it is clear that the technology could have widespread application for enhanced recovery from many difficult reservoirs. Mining access is a coming technology, and SATAC will be one of the leaders. By initiating the UTF program, the Authority has set the stage for much productive Research and Development over the next few years.



Underground Test Facility

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58

SESSION 1
PAPER 6

BLIND BORING THROUGH OIL SANDS
A TRAIL BLAZER

by

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TABLE OF CONTENTS

Page

Introduction 1
Project Description 2
Geological Setting 4
Alternate Shaft Sinking Methods 6
Site Preparation 10
Drilling Equipment 14
Drilling Operation: Shaft No. 2 19
Logging and Surveying 24
Steel Shaft Liner 25
Grouting Program 28
Access Stage Tunnelling 29
Summary 32
Acknowledgements 34
References 34
Photographs

LIST OF FIGURES

Figure 1 Project Location
Figure 2 Isometric Schematic of Proposed Development
Figure 3 Layout and Site Preparation for Blind Boring
Figure 3A Drill Rig Foundation Loads
Figure 4 Drilling Progress Shaft No. 2
Figure 5 Recommended Pressures for Liner Design

LIST OF TABLES

Table 1 Schematic Summary of Site Geology and Geological Conditions
Table 2 3.05 Meter Liner Design

BLIND BORING THROUGH OIL SANDS - A TRAIL BLAZER

by

M.A. Patterson, L.G. Cuthbert and D. Trimble

Introduction

A substantial portion of the Athabasca Oil Sands occurs at depths which render surface mining techniques uneconomical. Extraction of the bitumen from these deposits requires some degree of heating. Several methods have been investigated. The one with the greatest potential involves the collection of the bitumen from a network of horizontal or near horizontal wells drilled from tunnels within or below the oil sand deposits.

The overall success of this approach depends mainly on the feasibility of two concepts:

(a) The ability to gain underground access into and below the McMurray oil bearing formation; and

(b) The ability to extract oil from production wells in the deposits with the aid of steam pumped into the deposit through an auxiliary system of injection wells.

The latter concept is already a generally proven phenomenon after the successful undertaking of several experimental and pilot projects at various locations in the Athabasca deposits. However, shaft sinking through the weak, semi-indurated sedimentary rock overburden and the potentially unstable tar sands characteristic of the region have been unsuccessful prior to the achievement discussed in this paper.

Project Description

After approximately eight years of progressive studies, AOSTRA contracted the Harrison-Saturn Joint Venture to engineer and construct the access stage of the Underground Test Facility (UTF) on a turnkey basis. SNC Consultants Ltd. of Edmonton are providing engineering services to the Harrison/Saturn Joint Venture. Simmons/Santa Fe Joint Venture were subcontracted to sink and line the two shafts. Norwest Resource Consultants Ltd. of Calgary were involved in the project during the investigation stage and now act as project managers and owner's representative for the project.

The project is located approximately 60 km northwest of the town of Fort McMurray (Figure 1). The present contract is limited to the provision of access to the deeply buried tar sands and the construction of surface facilities in preparation for production. The main components of the project are as follows:

1. Sinking, and furnishing two 3.05 m finished diameter, steel and concrete lined shafts to depths of 213 m using blind boring techniques. Shaft No. 1 is for production and will be equipped with a headframe and hoist while Shaft No. 2 will be mainly for service lines, ventilation and emergency egress. Shaft No. 2 was drilled first because the requirements for verticality are less stringent.

2. Driving two development tunnels for a total distance of 350 m into the limestone underlying the Athabasca deposit.

3. Construction and installation of ancillary surface buildings and facilities.

Design and construction aspects of the shafts and tunnels are described in the following sections of this paper. A schematic drawing showing the required work is presented in Figure 2.

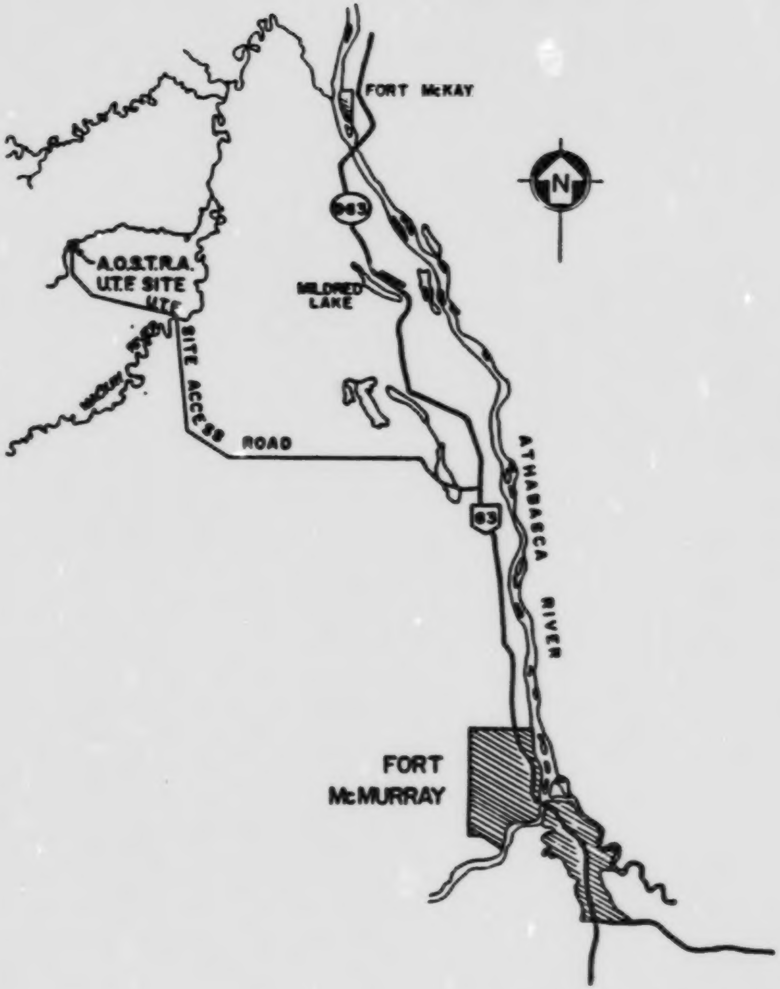

FIGURE 1.

LOCATION PLAN

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UNDERGROUND TEST FACILITY

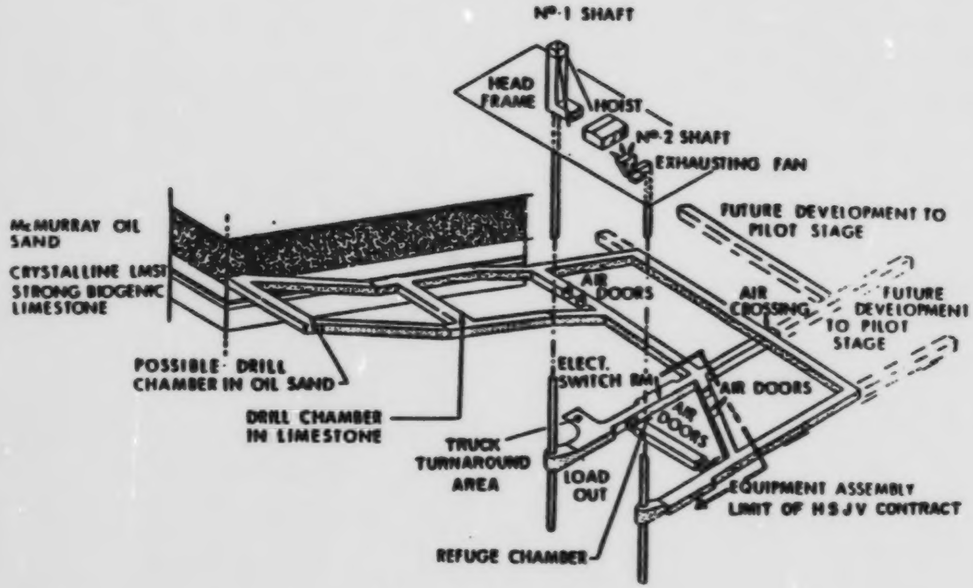

FIGURE 2
ISOMETRIC SCHEMATIC OF
PROPOSED DEVELOPMENT
(AFTER NORWEST)

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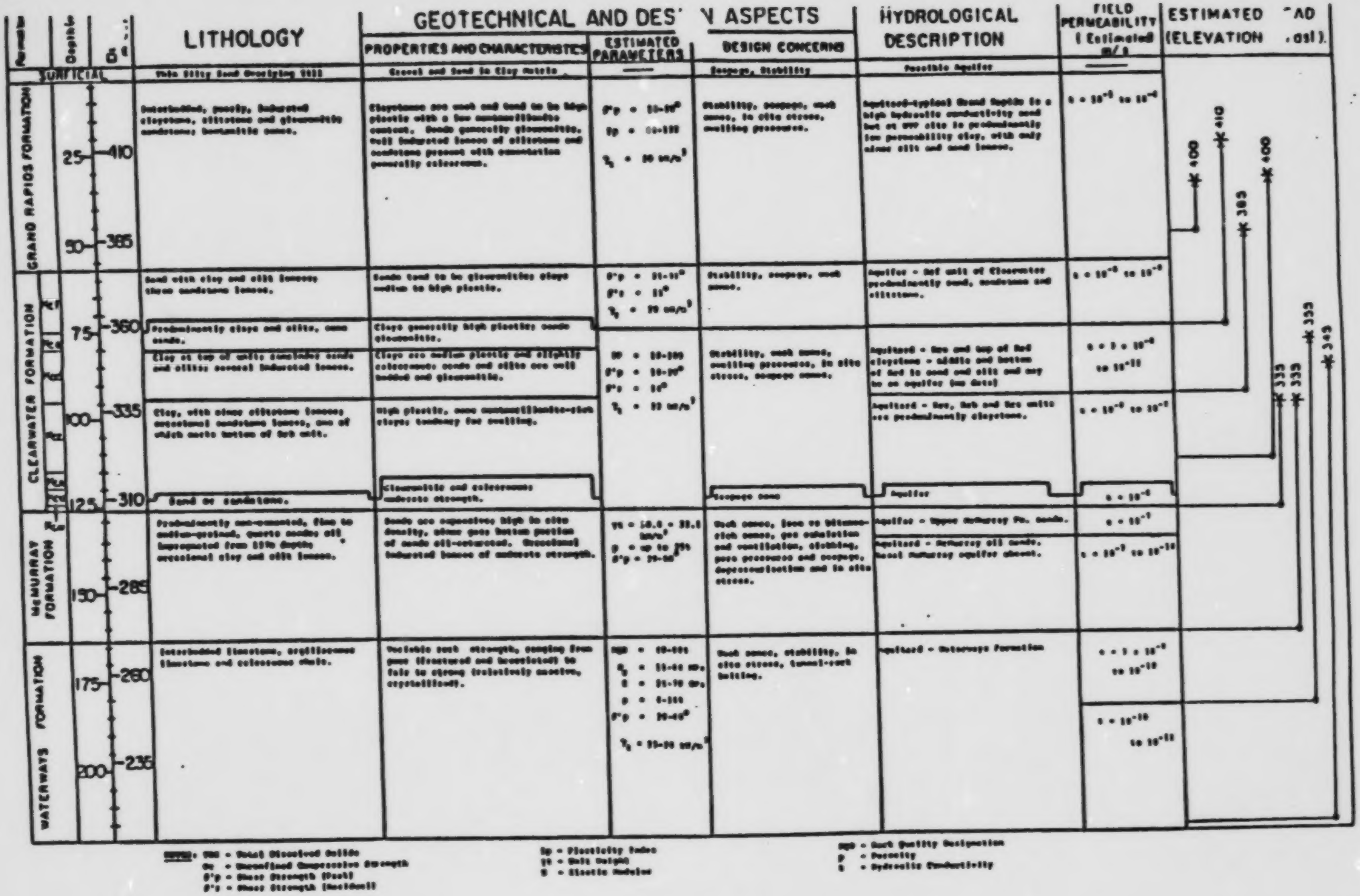
AOSTRA
UNDERGROUND TEST FACILITY

Geological Setting

The stratigraphic sequence at the site selected for the Underground Test Facility is typical of the Athabasca Basin. The regional geology has been described in several reports including those by Carrigy (1973), Norris (1973) and Dusseault (1977). The stratigraphy, geotechnical and hydrological characteristics of the site are summarized in Table 1. The geology from surface to total depth of drilling could generally be considered in three sections, each providing very different drilling and hole conditions.

Overburden Section:

The oil sand deposit at the UTF site is overlain by approximately 130 metres of interbedded claystones, siltstones and sandstones of the cretaceous aged Clearwater and Grand Rapids Formations. The Grand Rapids Formation is uppermost and underlies a thin veneer of unconsolidated glaciolacustrine silty sand and clay till. The Grand Rapids is approximately 55 metres thick and consists mainly of thick poorly cemented fine to medium grained feldspathic sandstone interbedded with laminated sandstone and silty shale.


Formation
Depth
El.
LITHOLOGY
GEOTECHNICAL AND DES' N ASPECTS
PROPERTIES AND CHARACTERISTICS
ESTIMATED PARAMETERS
DESIGN CONCERNS
HYDROLOGICAL DESCRIPTION
FIELD PERMEABILITY (Estimated m/s)
ESTIMATED "AD (ELEVATION .asl).
SURFICIAL
GRAND RAPIDS FORMATION
CLEARWATER FORMATION
McMURRAY FORMATION
WATERWAYS FORMATION
25
50
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260
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335
345

SCHEMATIC SUMMARY OF
SITE GEOLOGY AND
GEOTECHNICAL CONDITIONS
(AFTER HARDY ASSOCIATES, 1984)

TA~~E 1.

The Clearwater Formation lies conformably on the oil bearing McMurray Formation and is approximately 75 m thick. It is comprised mainly of grey, thinly bedded claystones, siltstones and fine grained sandstones. The engineering properties of the overburden section varies with lithology, degree of induration and type of cementing agent within the individual layers. Generally they can be classified as weak rocks. Reports on site investigations indicated the potential of flowing water and sand close to the bedrock surface. Most of the overburden materials tended to be unstable when exposed to water wetting. Core samples from even the harder formations showed a tendency to break down into unbonded fines if placed in water for a short period of time.

Reservoir Section:

The McMurray Formation locally is about 30 metres thick and consists mainly of weakly cemented rounded to subrounded quartzitic sandstone impregnated with bitumen and water. Fluvial, estuarine and marine facies of the formation have been identified by previous studies. The tar sand section has been well described in several reports.

Undisturbed it is a relatively hard, abrasive material which tends to wear drilling tools quickly. Once disturbed by drilling, it becomes a loose mass of unbonded sand particles in a bitumen matrix - the bitumen resembling thick roofing tar.

Sub-Reservoir:

The Waterways Formation lies beneath the McMurray Formation and consists of beds of greenish grey argillaceous and clastic limestones. Because of the relatively strong nature of this rock underlying the oil bearing strata, it is considered favourable for the underground tunneling development. It was initially considered to be benign and the least difficult drilling problem, but progress was much slower than anticipated in this section than in others.

Alternative Shaft Sinking Methods

The weak properties of the overburden and oil sands demand a shaft sinking method which would either preconsolidate the rock or provide support during or shortly after excavation. Methods which could be considered include:

i) Conventional excavation (drill and blast or clamshell) followed closely by ribs and lagging or steel liner plate.

ii) Preconsolidation grouting.

iii) Ground freezing.

iv) Large-diameter drilling with mud for support.

Disadvantages of the first method would be its time-consuming nature, requirement for highly skilled workers to install the support rapidly and the required precautions for personnel working in the shaft. Any significant inflows of water and/or fines into the excavation could cause increased shaft sinking costs and schedule delays. In the extreme, such problems could be insurmountable as was the case in the G.C.O.S. attempt in 1963.

The effects of cement grouting in the local silty and clayey materials of low hydraulic conductivity would probably be small. The presence of oil in the material further makes the effects of the preconsolidation method unpredictable.

The latter two methods were given serious consideration during the planning stages of this project. The ground freezing method was eventually eliminated for various reasons. In general, it was considered feasible for the overburden materials but unpredictable for the oil sand zones for the following reasons:

- low moisture content preventing frost penetration
- low hydraulic conductivity preventing artificial saturation
- high chloride and sodium content depressing the freezing point

- inability to control gas exsolution thus causing alteration of soil structure and subsequent instability
- low unconfined strength of frozen disturbed oil sands near the shaft walls

Large-diameter blind shaft drilling was the method chosen as it offers some particular advantages over conventional shaft sinking techniques. Four of these advantages were considered important in making the decision to drill the shafts required for the access stage of the AOSTRA UIF Program.

These include:

- the ability to control ground water and unstable formations through the use and manipulation of a suitable drilling fluid.

- speed, and predictability of the construction period.

- prevention of gas exsolution from the oil sands thus preserving its in-situ strength.

- safety, since men are not required to enter the shaft until it is completely lined.

The success obtained in drilling Shaft No. 2 and the upper portion of Shaft No. 1 to date indicate that the relatively low degree of disturbance incurred by this method and the polymer drilling fluid used were adequate to maintain the stability of the shaft walls within these critically weak formations.

Site Preparation

The blind boring method requires a relatively extensive site preparation program to facilitate the drilling process. Facilities installed at each shaft site on the UIF project specifically for drilling support included the following:

- A 4.7 m diameter conductor hole, 15.24 m deep for assembling the drill bit and mandrel.

  This conductor hole or foreshaft was augered full depth to a diameter of 5.3 metres. A pre-assembled liner consisting of 5 mm thick Armco steel liner plates was then lowered into the augered hole. To counteract theoretical earth pressures, the lower 5 m of the liner was stiffened with M100 x 19 steel ribs on 0.5 m centres with timber blocking. After installation of the conductor hole liner, a lean concrete mix was poured in the annular space between the Armco steel liner and excavation walls.

  Reference to weak uncemented sand layers within the upper 30 metres of bedrock had caused some concern about the feasibility of augering the conductor holes without support. Conventional step by step excavation followed by immediate installation of the Armco liner plates was given serious consideration. Preliminary site trials with pilot holes of 0.76 m and 1.5 m diameter were performed. These tests indicated a general shaft wall stability and longer stand-up times than originally predicted, hence the augering method was selected. No instability was encountered during construction. It should be noted that since the conductor holes were excavated in winter, freezing of the shaft walls was an additional benefit.

- An engineered foundation for the drill rig.

  This foundation was constructed after completion of the conductor hole and consisted of reinforced concrete slabs of varying thickness and reinforcing steel requirements. The central portion consisted of a 1.015 m thick slab founded on 8 vertical and battered concrete caissons designed for the full weight of the drill rig and potential hook loads of up to 1,000,000 pounds. Slabs to the front and rear of the central portion were 230 mm thick and founded on a 300 mm thick pad of compacted sand and gravel.

- A buried steel pipe and sump for mud circulation.

  The pipe was 406 mm diameter connected to a sump 610 mm in diameter, designed to gravity feed re-processed drilling fluid into the shaft opening during dilling.

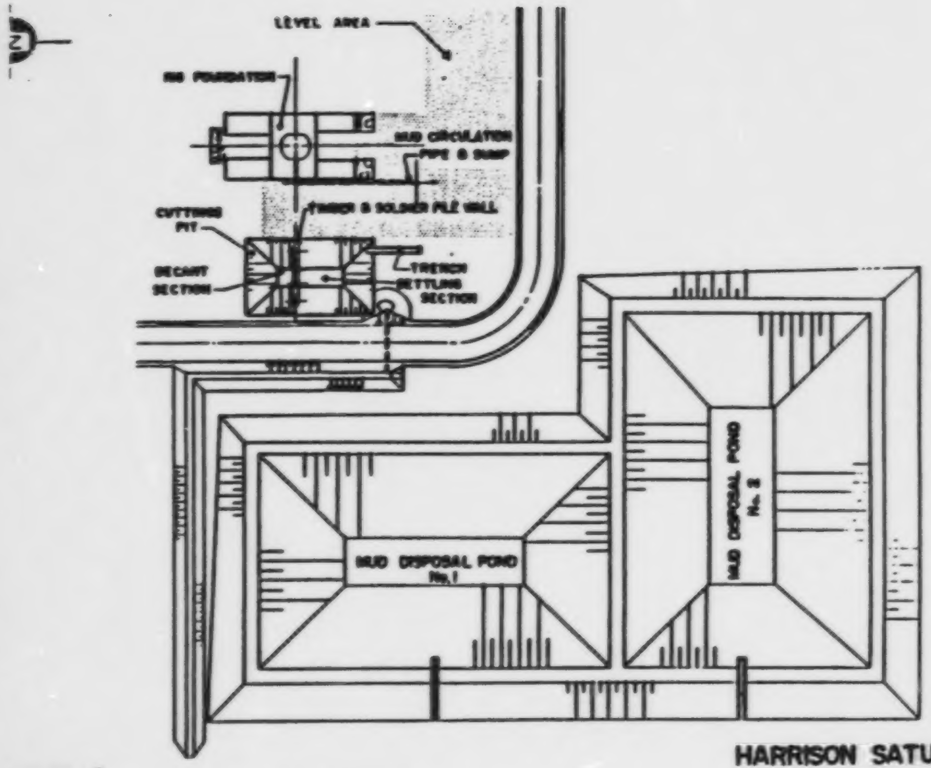

FIGURE 3
LAYOUT AND SITE PREPARATION
FOR BLIND BORING

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UNDERGROUND TEST FACILITY

- A cuttings and decant pit for removal of the coarser size fraction of drill cuttings.

  This pit consisted of a trapezoidal shaped excavation divided by a soldier pile and timber baffle wall to form separate settling and decant areas. A mud slab was poured on the side slopes and bottom of the pit to minimize erosion and damage to the pit by the clamshell during removal of the settled drill cuttings.

- A 3500 cubic-metre mud disposal pond

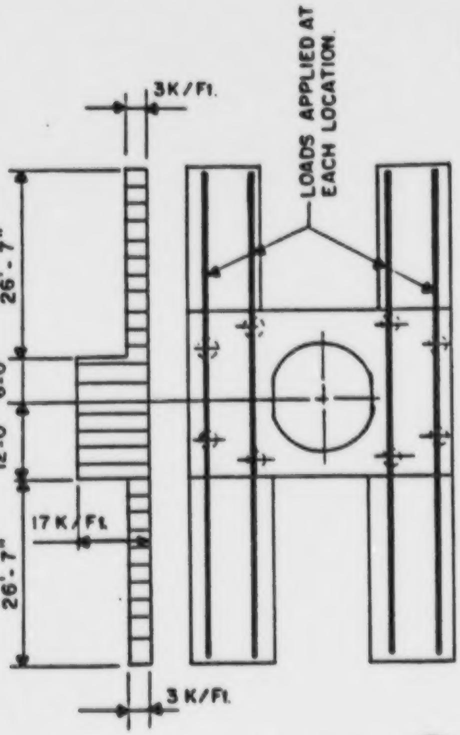
  A clay lined trapezoidal shaped pit with perimeter berms was provided to store the excess mud after it is displaced by the liner installation and grouting operations.

A schematic layout of these facilities is shown in Figure 3.

The design loading diagram for the foundation is shown in Figure 3A.

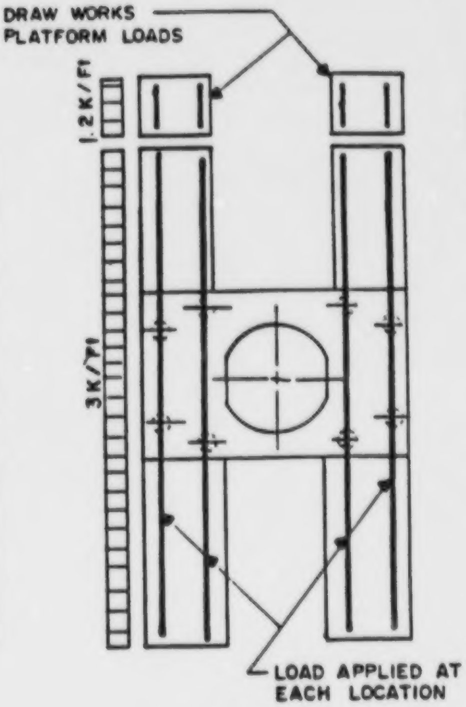
LOAD COMBINATIONS

CASE ①
CASE ②
CASE ② + CASE ③
CASE ② + CASE ④
CASE ② + CASE ⑤



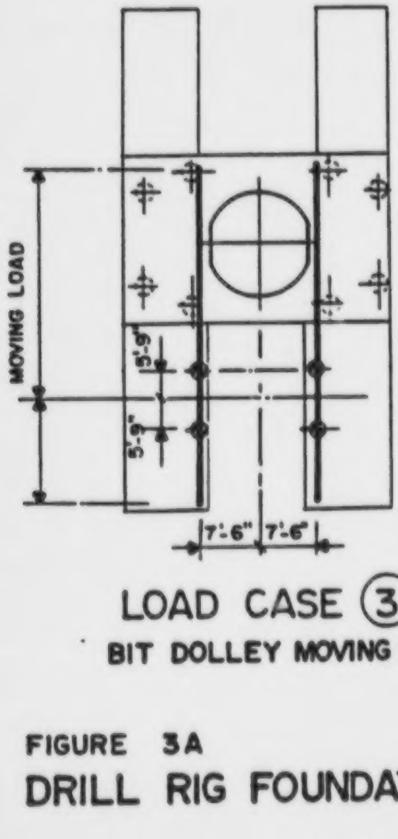
LOAD CASE ①

500 TON RIG LIFT & RIG DEAD LOAD



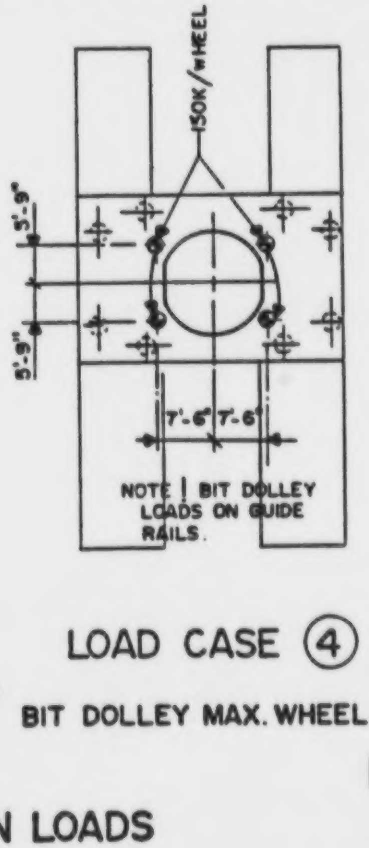
LOAD CASE ②

RIG DEAD LOAD



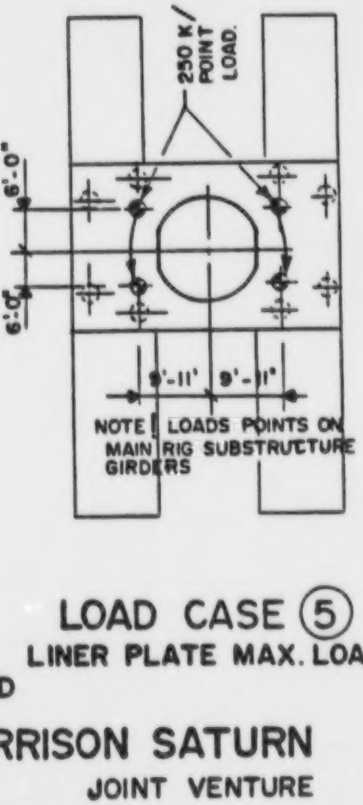
LOAD CASE ③

BIT DOLLEY MOVING LOAD



LOAD CASE ④

BIT DOLLEY MAX. WHEEL LOAD



LOAD CASE ⑤

LINER PLATE MAX. LOAD

FIGURE 3A
DRILL RIG FOUNDATION LOADS

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UNDERGROUND TEST FACILITY

Drilling Equipment

Assembling the drilling equipment for this job proved to be an interesting exercise in logistics.

Regent Rig #14 was one of a few Canadian rigs which provided the combination of physical and structural capabilities required to handle the drilling and lining operation.

Rig #14 is equipped with an Oilwell 840E drawworks, depth rated (in standard operating configuration) to 6100 m. Maximum hook load is 445,000 daN (1,000,000 lb.) when rigged with 12 lines.

The mast and sub are a Dreco self-erecting design with a 43.28 m, (592,000 daN) GMC mast and 9.91 m substructure with a nominal 5.75 m sub support leg spread.

The modifications required were relatively simple. The structure, braces, mast, flat back frames, etc. were changed to provide a clear 2.2 m swing from ground level to a height of approximately 18 m.

This required that the drawworks support table and beams be modified so that the drawworks could be moved 0.4 m to the rear, away from the hole center.

The 37 1/2" rotary table was replaced with an Oilwell 49 1/2" table. The rotary drive was modified to include a 2.63 to 1 jack shaft drive reduction so that rotary speed could be easily controlled in the range of 4 - 20 RPM. This reduction also provided for increased rotary torque output potential.

It was decided early on in the program, that the bottom hole assembly would be handled entirely under the floor and that the casing elevators would be suspended on a strong back beam system located at ground level.

A bit dolly and rail system was built to transport bit bodies in and out from under the drilling assembly and clear of the substructure and floor.

The bit dolly and rail were removed and replaced with the strong back beam assembly for running the liner.

Other modifications included the addition of an air mud separator on the fluid return line and modifications to suction lines, flow lines and skimmers in the mud tanks. These changes were necessary to accommodate the large fluid volumes associated with the circulation system. Additional solids handling equipment was also required to process the large fluid volumes.

Some additional equipment was also added to the rig. A series of four 25-CMM, 2400 kPa air compressors were incorporated. These were necessary to operate the air assisted reverse circulation system.

A Normix mixer, supplied by a D-1000 duplex pump was also added to provide the ability to quickly and efficiently mix drilling fluid.

A number of large diameter drill bits were considered for this project. It was finally decided to use a Drilco flat bottomed bit

design incorporating 16 cutters of which 12 were 38.7 cm dia. x 30 cm ST type cutters. The center cutters consisted of two type 24 CC with cantilevered supports and two MT style cutters. Each cutter was preceded by an aimed fluid nozzle.

The total bottom hole assembly, consisting of the bit body, mandrel and weight stool, stabilizers and donut weights, weighed 205,000 daN.

The drilling rig and tools were totally rigged up at Regent Drilling's yard in Edmonton prior to moving the equipment out to the AOSTRA test site. This provided us the opportunity to check that each of the modifications had been handled properly, that all the new components fit and that each additional piece of equipment would mesh into the overall drilling rig arrangement as required to drill the hole.

It is worthwile to note that each of the structural modifications made to the rig were handled in such a way that items requiring change were removed in total and replaced with suitably modified structural components. With one exception, the replacement structures are designed and built to be pinned in place. When this job is finished, the rig can be restored to original as-built condition by pinning the original components back into the rig. The modified components will be available for reuse when another big hole job becomes available.

The only minor exception is the drawworks support table and beams. Although the design modifications are suitable for both big hole drilling and for conventional work, they could not be easily built as replacement parts. The rig will continue to operate with that change in place.

The Dreco self-erecting design allowed for easy conversion of the rig from the drilling mode to the configuration required to run the liner. The set back table, rotary support beams and floor were removed from the rig. A space frame prefab support structure, complete with two 2.3 m wide doors was added so that the area within the rig structure could be maintained relatively wind free as required when welding the casing. The changeover from the drilling mode to the liner running mode was handled in less than 24 hrs.

Drilling Operation: Shaft No. 2

On site rig-up was started January 21, 1985 in cold miserable weather. In spite of the conditions, the rig-up went well and Shaft No. 2 was spudded February 4 at 03:00. The drilling progressed as planned with minor problems in handling the drilled solids produced from clay layers in the formation. Bit balling and plugging of the solids handling equipment presented difficulty until the mud system was balanced to the point where these conditions could be handled. The polymer lubricant system utilized, proved both simple and effective in protecting the clay shales from water wetting and consequently extremely effective in stabilizing the hole. The lubricant did its job in controlling the bit balling and clogging problems and in eliminating the mud balling and screen blinding (coagulating) problems in handling the drilled solids through the surface solids control equipment.

The section from surface to the top of the tar sand was drilled in an elapsed time of 24 1/2 days. The actual drilling time was 497 hours on the bottom of an average penetration rate of 00.2378 m/hr. or 0.78 ft./hr.

BLIND BORING THROUGH OIL SANDS - A TRAIL BLAZER

The tar sand section, which ran from approximately 142 - 174 m was drilled in 5 1/2 days elapsed time. The actual time on bottom was 102.5 hrs. for an average penetration rate of .3122 m/hr. or 1.024 ft./hr. Figure 4 shows the actual vs scheduled drilling progress.

The drilling through this section was consistent with little difficulty. The major problem was handling the bitumen. It tends to be like roofing tar - difficult and messy to work with. While the mud was travelling through the system, the surfactants in the mud lubricant, coupled with pH controlled to 8.5 - 9.0 managed the bitumen well. The material however, tended to separate out as the fluid flow and associated agitation was reduced. It would then float to the surface as a gooey mass. At one point a large accumulation was allowed to collect at the top of the borehole fluid column. It had to be steamed and removed with a special high vacuum truck equipped with a large suction line. A conventional oilfield vacuum truck was incapable of pulling the material through the suction line.

Two short trips were made while drilling the tar sand section. This was done to check for indications of hole swelling or caving. There was none in evidence.

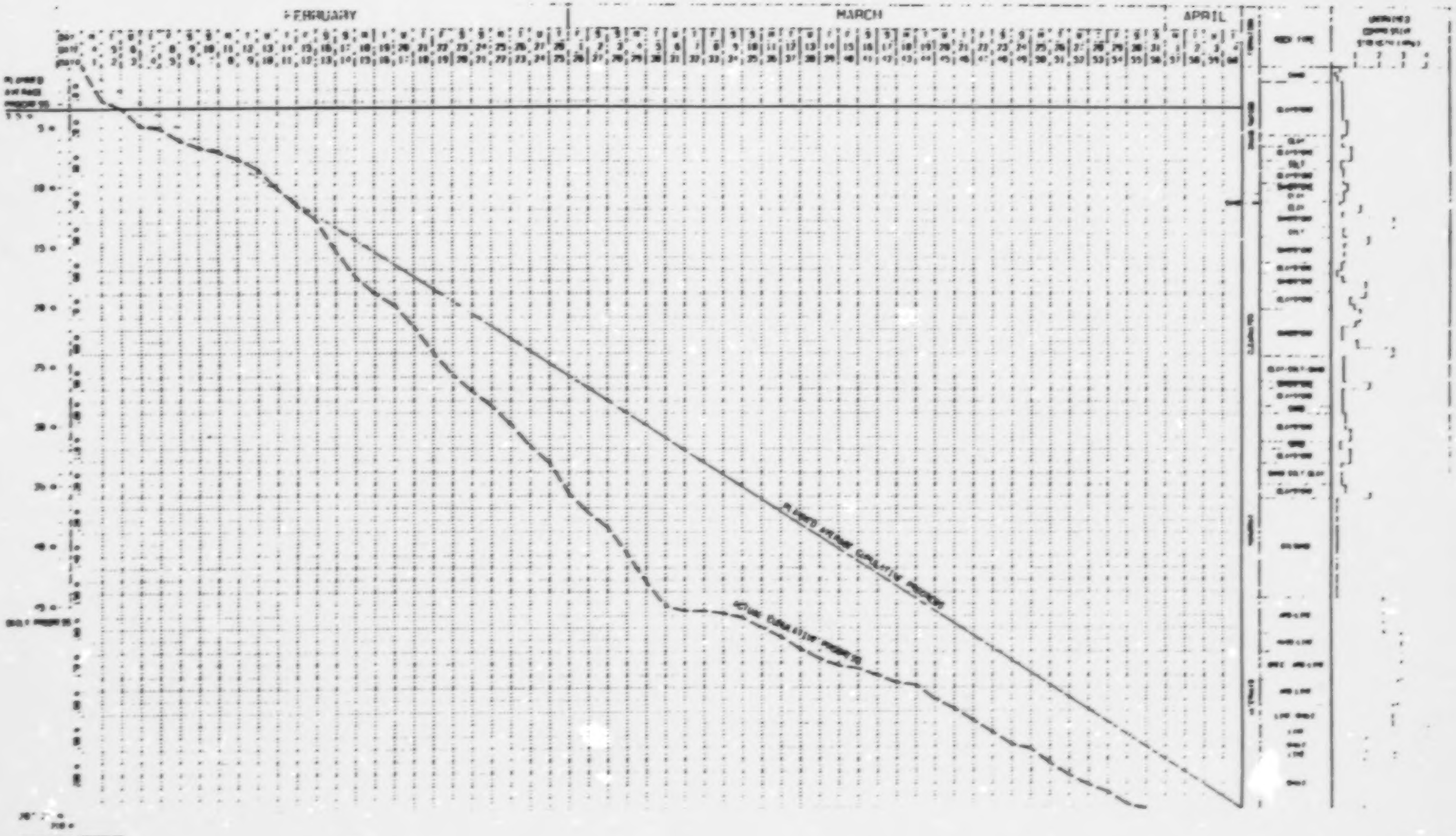


FIGURE 4. DRILLING PROGRESS SHAFT NO. 2

At the bottom horizon of the tar sand section, the rate of penetration suddenly dropped. Time was spent in trying variations on the drilling parameters of weight, rotary speed and circulation rate in an attempt to achieve some better progress. When no encouraging results were obtained, it was decided to pull and check the bit.

Once on surface, inspection found the cutters to be in fairly good condition. The teeth showed limited wear although minor tooth tip damage was in evidence. Some bearings were also showing signs of wear. A decision was therefore made to change the bit. During the change, a bit body bolt and nut were inadvertently dropped into the hole resulting in our only fishing job to retrieve it. The old bit body was run back in and rotated in an attempt to jam the junk into one of the cutters or to shove it to the side in the formation. After an elapsed time of about 10 hours, we had indications of increased torque and decided to trip the bit out of the hole. Both the bolt and nut were recovered, jammed into the cutter assemblies.

The bit was changed without incident and the new drilling assembly run to bottom and rotated for a total 156.75 hrs. During this time, the drilling parameters were varied in an attempt to achieve some reasonable penetration. The rate of penetarion stayed low at an average of .11 m/hr.

During this interval, the formation was a chalkie limestone interbedded with clay and the occasional hard limestone stringer. The cuttings circulated out of the hole tended to be balls of chalkie fines with small limestone chips mixed in. The material came across the shakers in small balls of about 10 to 20 mm, occasionally larger. The balls were compacted but relatively dry inside when broken open.

As an experiment, a bit body was dressed with a set of carbide insert cutters. These cutters were designed to provide a "kerf cutting" action.

The bit was run in and drilled for a total of 52.25 hours at an average penetration rate of 2 to 2 1/2 hours per .2 m. Variations on the drilling parameters of weight, rotary speed and fluid circulation rate did not result in any significant or sustained improvement in drilling. The bit was pulled and the second bit, with steel tooth cutters was refitted and run back in.

The drilling problem observed was common to both the steel tooth cutters and the carbide insert bit. The chalkie limestone tended to break into fine granular cuttings rather then fair sized chips. These chalkie cuttings were packed tightly between the cutter teeth, (or rows in the case of the kerf cutter,) and limited the ability of the teeth to penetrate the formation. On removal of the bit from the hole, the chalkie cuttings packed between the teeth could be removed only by physically digging them out with a screw driver or other suitable tool. When hard stringers or more competent layers of limestone were encountered, they would tend to clean the bit up and allow a higher rate of penetration for short periods of time.

We finally reached total depth at 18:50 on March 30, 1985, 54 3/4 days after spudding in. The penetration through the bottom section was 0.099 m/hr., a rate below that estimated for the completion of this portion of the hole.

Logging and Surveying

After completion of the drilling, the bit was short tripped through the tar sand section and back to bottom to check for indications of any hole problems. We found no indications of hole swelling or sloughing and had indications of only 1/4 m of fill on going back to bottom.

Two surveys were run. In the first, a series of surveys were taken in the drill pipe from the bottom of the hole to the top. The results indicated that the center of the hole at the bottom was in line with the center of the rotary table at the rig floor.

A second survey was taken at 10 m intervals while tripping the drilling assembly out of the hole. This survey indicated some deviation and that the hole center at the bottom was approximately 1/2 m offset in an easterly direction. The results of this survey are in question because of the physical limits available to centralize the instrument in the bit body and in the ability to read the instrument accurately with the extremely small inclinations indicated. It is our opinion that we drilled a straight vertical hole.

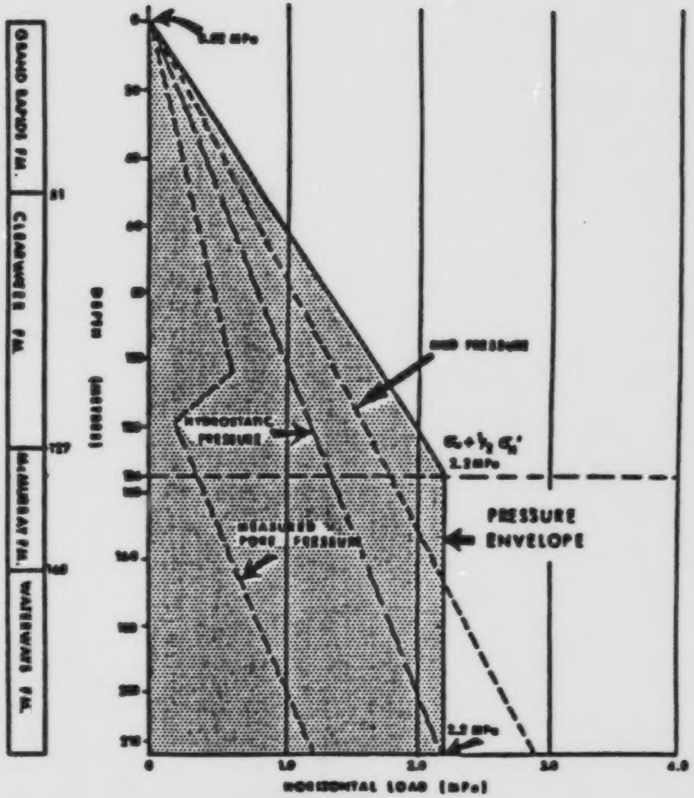
BLIND BORING THROUGH OIL SANDS - A TRAIL BLAZER

Two separate attempts were made to obtain an accurate log of the hole. In the first case, two separate sonar logging tools were run. These were of the type commonly used to log underground storage caverns. Neither was able to obtain any meaningful readings. It was felt that the makeup or solids content of the drilling fluid was adversely affecting the ability of the tool to get a definitive sonar bounce from the side wall of the hole. The output readings indicated a hole of much smaller diameter than that actually drilled.

Finally, a modified four arm caliper was run in the hole. The results obtained could not be considered reliable and the exercise was abandoned.

Steel Shaft Liner

A 3.05 m I.D. stiffened ring, thin wall steel liner was designed to withstand the horizontal load pressures shown in Figure 5. An exception was taken for the bottom 30 m where a hydrostatic head of 1,198 kg/m^3 drilling fluid was used. A 1.5 safety factor was added to these pressures and used as a design pressure.



UTF SHAFT
RECOMMENDED PRESSURES
FOR LINER DESIGN

FIGURE 5

Three principal loading conditions were considered in the liner design:

1. Liner weight
2. Hydrostatic/lithostatic pressure, and
3. Fabricated out-of-roundness

The design was evaluated for maximum stress levels, overall elastic collapse pressure, and elastic panel collapse between the stiffeners due to instability.

The optimum design was determined by considering the thickness of the steel plate, the diameter/plate thickness ratio, the strength of the material, out-of-roundness tolerance, the height and thickness of the stiffener rings and the spacing of the stiffener rings.

A summary of the liner design can be found in Table 2. The shell of the liner was fabricated with 300 WT steel and rings with 300 W steel. The liner was manufactured by Strathcona Steel Manufacturing Inc. of Edmonton.

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JOINT VENTURE

3.05 METER LINER DESIGN

Depth (Meters) From	To	Design Pressure (K Pa)	Wall Thickness (mm)	Stiffener Ring Size (mm x mm)	Ring Spacing (mm)
211.5	201.5	3,762	20	100 x 173	1,111
201.5	189.5	3,557	20	100 x 173	1,200
189.5	117.5	3,300	20	100 x 173	1,333
117.5	105.5	2,836	20	100 x 173	1,500
105.5	93.5	2,567	20	100 x 145	1,500
93.5	81.5	2,279	16	100 x 145	1,200
81.5	69.5	1,990	16	100 x 145	1,333
69.5	57.5	1,701	16	100 x 110	1,500
57.5	33.5	1,413	16	100 x 90	1,714
33.5	0	1,037	16	100 x 60	1,714

TABLE 2.

The first section of liner, the K unit was lowered into the hole April 3, 1985. The liner was floated into place by filling the interior with fresh water.

The liner joints were welded using a hard wire MIG process. On average, each joint required about 6 hours with a 6 man welding crew to complete the circular seam.

Once the welding was completed, each joint was inspected using an automatic ultrasonic scanning system. Indications of problems within the weld were further checked by a manual ultrasonic scan to verify the presence and extent of defects. Defects requiring repair were ground out, rewelded and reinspected to verify a suitable correction. During the program, the results of the automatic ultrasonic evaluation were verified by doing a second inspection using a radiographic technique. The results correlated exactly. The last section of liner was welded and lowered into place April 16, 1985.

It is interesting to note that during the installation of the liner, it was possible for one person to rotate the liner by hand while it was hanging from the blocks. Upon the addition of the last liner section, some fill or wall sloughing was encountered and single handed rotation was no longer possible.

The fact that the liner hung free is the best indicator we have as to the effectiveness of the mud system to maintain hole stability and to the fact that we were able to drill a straight hole.

Grouting Program

The liner was grouted in place using a total of 1164.5 T (1117.6 m^3) of cement, placed in 6 stages over a period of 6 days. The lower three stages, up to 155.5 m from ground level used neat Class A oilfield cement. The remainder used Class A plus 4 1/2% gel. The top stage was stopped at 7.5 m below ground level to allow for easier installation of the ventilation shafts.

Access Stage Tunnelling

It is planned to establish a production level at the 180 metre depth by excavating a 4 m x 5 m drift from each of the shafts and interconnecting them by two cross-cuts as shown in Figure 2. Facilities to be built at this stage are shown in the figure and include a slusher trench and loading pit, truck turnaround area, explosion proof electrical substation and switch room, sedimentation sump and pump station, equipment assembly area and a refuge chamber with bulkheaded air locks on either end.

Before break-out from the shafts the adjacent strata has to be tested for the presence of gas and water. This will be done by drilling the rock to a depth of 2 meters from the inside of the shaft through pre-installed ports in the steel liner. If objectionable gases or water flows are present, remedial measures such as grouting and methane drainage will be undertaken. This testing process will be repeated before every face advance.

The next operation will be opening of a one-metre square in the steel casing. Several methods of cutting the steel such as mechanical, chemical, high pressure water jet and shaped explosive charges have been examined. The use of an air arc has been chosen because it is economically well understood and requires minimum experience for operation.

Once the plate is removed, the exposed rock and grout will be drilled, loaded with selected explosives and blasted. The excavation will then be enlarged with appropriate adjustments to the blast pattern if required.

Initally the rock debris will be loaded by hand. As the excavation lengthens a slusher will be employed until sufficient room is available to operate a diesel powered two cubic yard capacity loader. This unit will load, remove, and transport the blasted rock to the hoist bucket which will take it to the surface for subsequent disposal.

The rock will be drilled with jack-legs in a pre-designed pattern. The outer perimeter holes will be loaded with a cutting explosive and the inner holes with a lifting explosive. This designed explosive plan should give smooth walls, roofs and blasted rock of optimum size. All explosives will be of the type permitted in gaseous mines.

It is expected to drill 2 metres per round and to pull 1.7 metres. Exploration holes will be drilled in advance of the face to disclose the geology and possible water and gas occurrences as described before.

This relatively simple and unsophisticated method of excavation is chosen because the short runs and numerous changes in direction and dimensions are not conducive to mechanical means of excavation. The rock is expected to be competent and the amount of support will be kept to the minimum. The main support method will be resin-anchored rock bolts. The holes for these rock bolts will be drilled with stopers. In the area of the loading pocket, machinery assembly bay and the refuge chamber, the crown will be shotcreted for additional strength.

Fresh air will be forced to the face by surface fans through ducting. This system will keep the work area ventilated and will also exhaust any noxious gases emitted by the rock and left after

blasting. Other safety precautions will include intense monitoring of the underground environment. All underground workers in addition to the usual safety clothing and footwear will carry a self rescuer breathing unit.

After excavation has been completed, the gantry, slusher pit, loading pocket, transformer vault, and drainage sump will be constructed and their equipment installed. Besides these items a fire line, lighting, communication equipment and monitoring instrumentation will be mounted along the walls.

Summary

In summary, the site preparation drilling and lining of Shaft No. 2 went well. Indirect difficulties associated with water supply, low temperatures and soft lease roads and access road conditions did not substantially affect any portion of the program. Directly related problems such as gumming and balling of the drill bit by clayey material and bitumen can be overcome by control of the drilling fluid and suctioning. The slow drilling progress encountered in the limestone would still compare favourably with rates for other methods. The overall shaft-sinking rate was much greater than could have been achieved by the more conventional methods.

The biggest surprise was the difficulty in drilling the lower portion of the hole. Evaluations are currently underway to determine if changes to the cutter assembly, or cutter design, and the fluid circulation system might result in increased rates of penetration and a shorter time to completion.

The effectiveness of the drilling fluid program in achieving and maintaining hole stability is considered a major success in this experimental project.

The success achieved in drilling Shaft No. 2 and the upper portion of Shaft No. 1 to date is practical confirmation of the theoretical viability of the blind boring method for accessing the deeply buried Athabasca tar sand deposits.

ACKNOWLEDGEMENTS

The authors wish to thank AOSTRA and Norwest Resource Consultants Ltd. for the permission and opportunity to publish this paper and for the use of resource material on the overall project.

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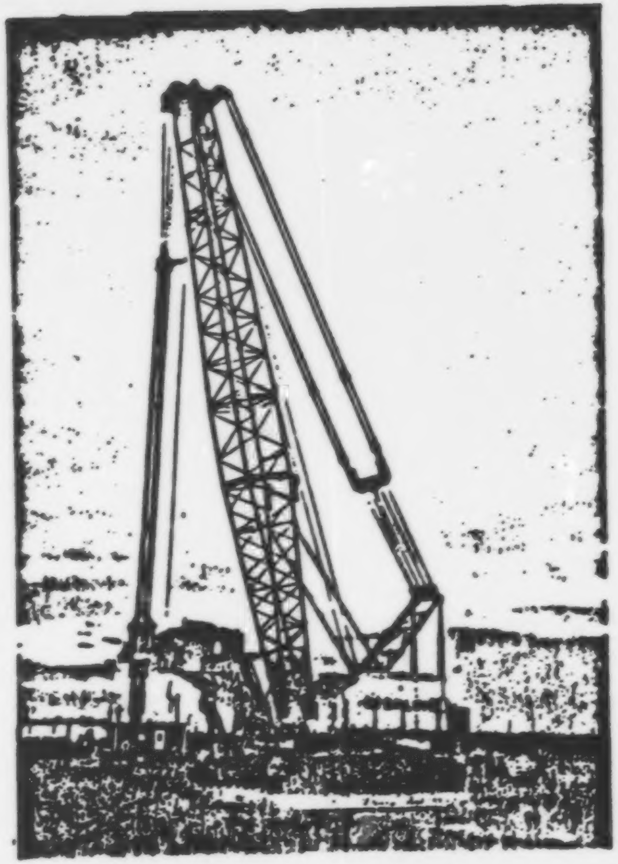
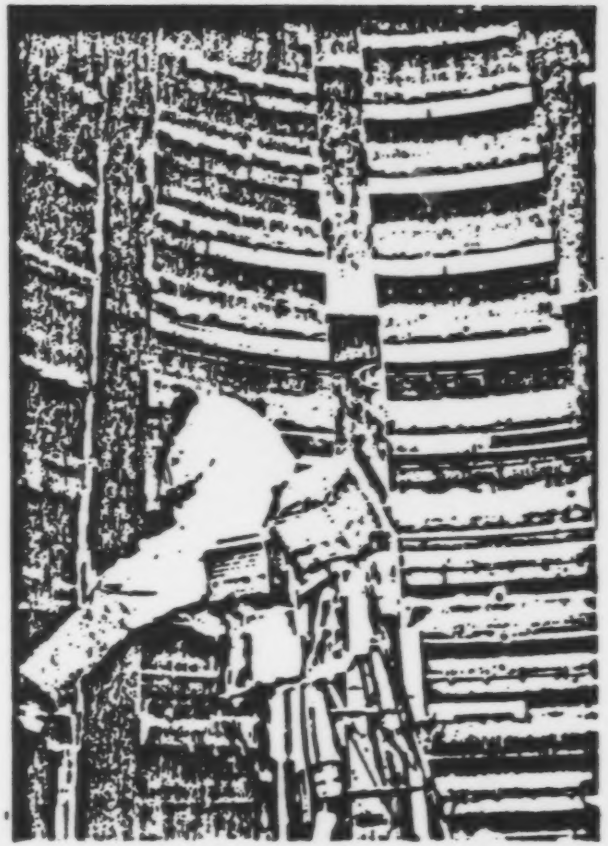
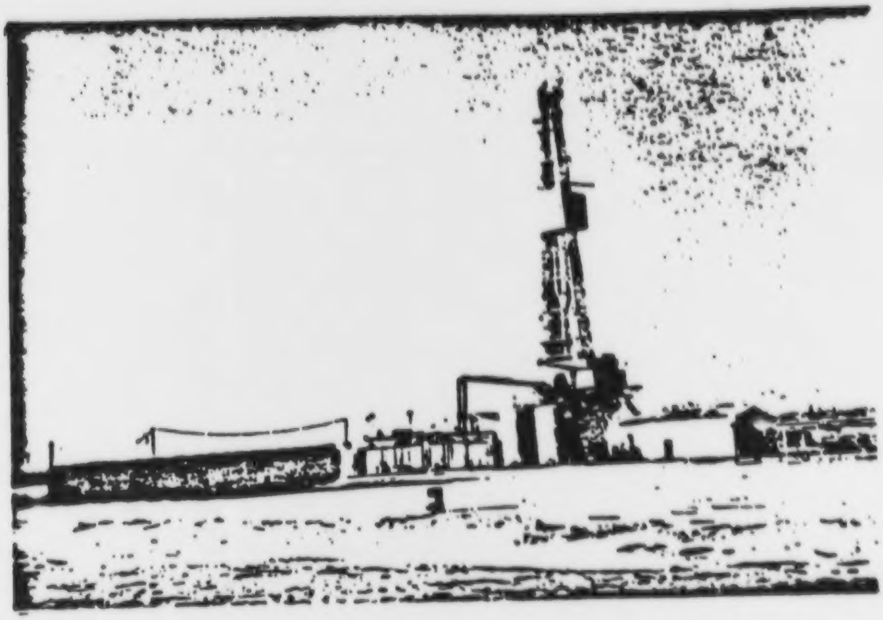
PHOTOGRAPHS



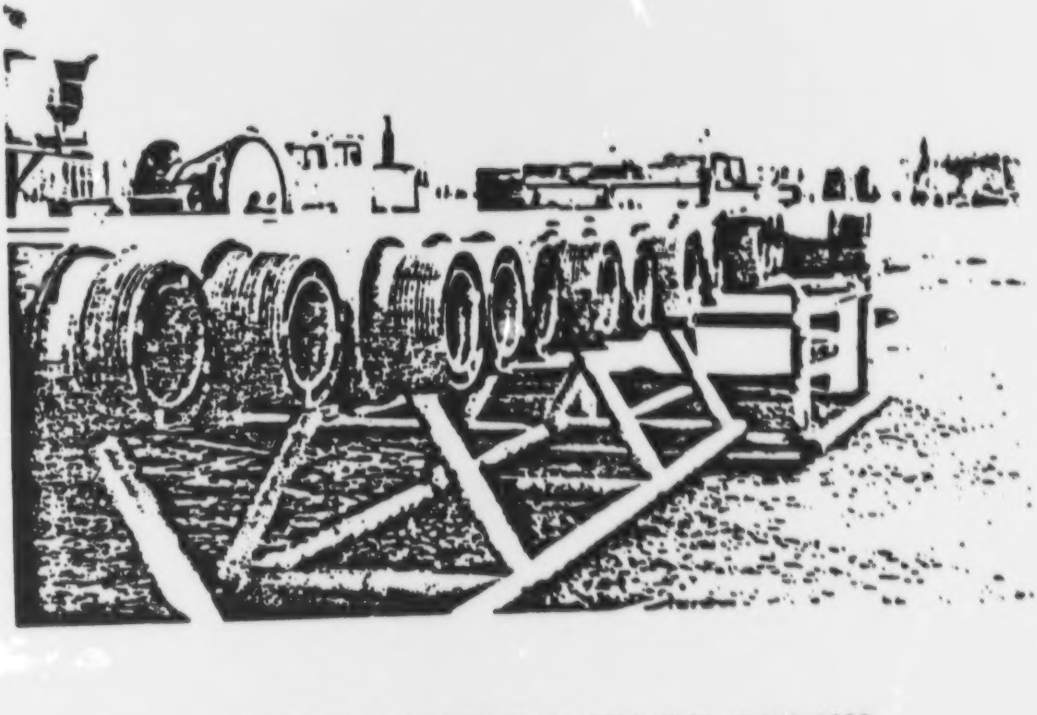
NO. 1 AUGER RIG MOUNTED ON 165 TON CRANE FOR DRILLING 5.3M DIAMETER CONDUCTOR HOLE TO 15.25M DEPTH



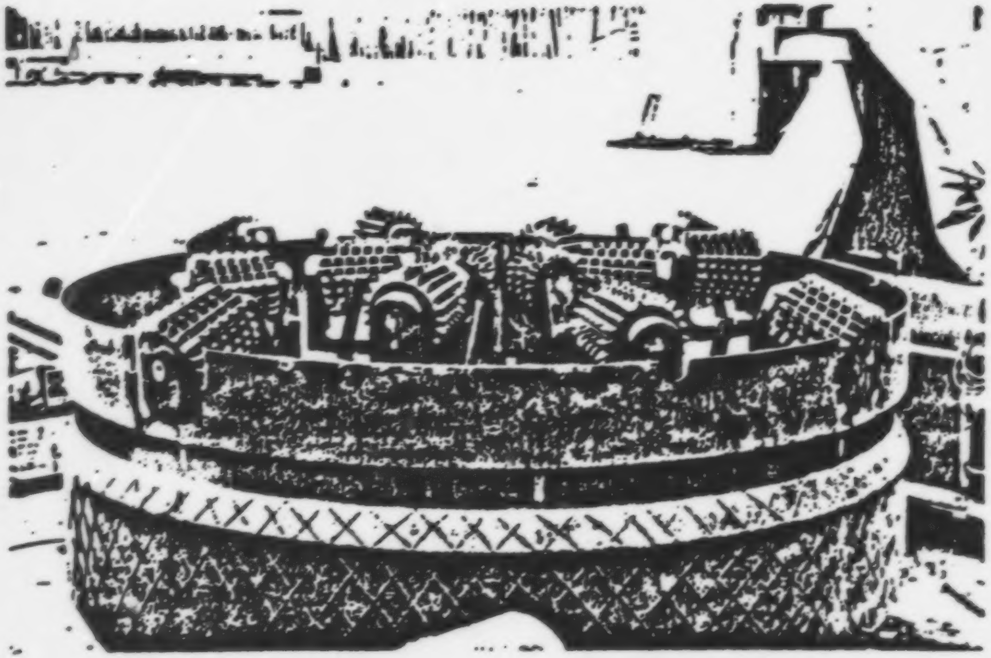
NO. 2 PRE-ASSEMBLING RIBBED SECTION ON CONDUCTOR HOLE LINER



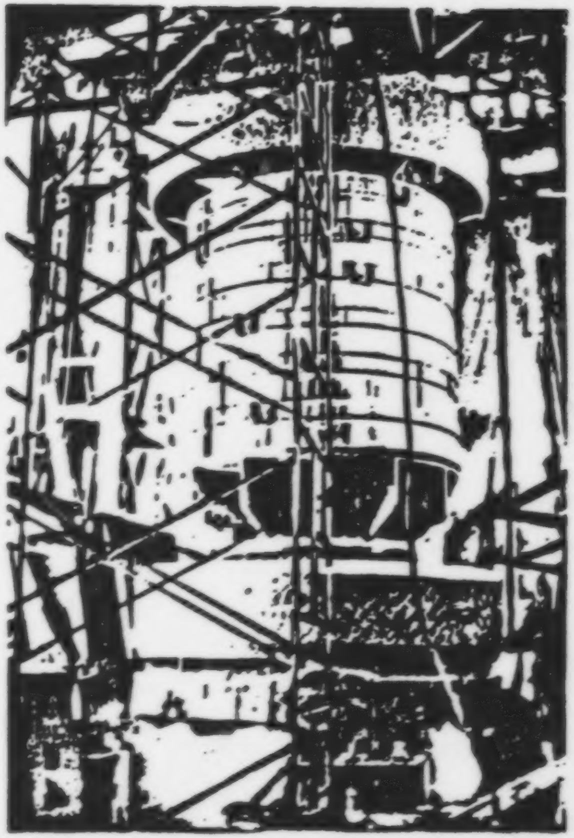
NO. 3 REGENT RIG 14E. OIL WELL 840 E
MODIFIED AND RIGGED UP FOR BIG HOLE DRILLING.



NO. 4 13 3/8" DUAL WALLED DRILL PIPE WITH HUGES H490
TOOL JOINTS.



NO. 5 DRILCO 13' DIAMETER FLAT BOTTOMED BIT



NO. 6 BOTTOM HOLE ASSEMBLY TOTAL WEIGHT
APPROX. 500,000 LBS.

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Advances
in Petroleum
Recovery &
Upgrading
Technology
1985

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AOSTRA

59

SESSION 1

PAPER 4

DRILLING OIL WELLS FROM UNDERGROUND

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DRILLING OIL WELLS FROM UNDERGROUND

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A. Strickland, Norwest Resource Consultants Ltd., Calgary

bstract

rilling, completing and servicing horizontal stimulation and production wells from a ine environment presents a new set of problems to the oil field drilling engineer nd the mining engineer. Conventional technology exists for much of what is needed, ut not in proven systems suitable to an underground operation. A considerable evelopment program will be undertaken as part of the AOSTRA Underground Test acility Project. This paper outlines the problem and notes the available technology. ome preliminary conclusions on system concept are presented.

.0 INTRODUCTION

From the start of the project, it was realized that the task involved more than just a drill. To place completed wells near the base of the oil sands, from underground tunnels, demanded not only a special drill, but a drilling system to go with it.

The close collaboration of Petroleum drilling engineers and underground coal mining engineers is proving to be invaluable for the efficient development of the project.

2.0 THE MINE TUNNELS

Following examination of exploration cores and rock qualities, two tunnel horizons have been selected: (see Figure 1)

- one, 20 m below the base of the oil sand, which will be used for the access and main ventilation tunnels:
- the other, has a roof formed by a strong bed of crystalline limestone 8 m below the base of the oils sands. Drilling will be carried out from this tunnel.

Tunnels 5 m wide, 4 m high can be supported at modest cost using roof bolts supplemented by wire mesh and shotcrete if necessary. These dimensions will allow the drilling machine and its accessories to pass with adequate clearance.

3.0 TAKING THE DRILLING MACHINE UNDERGROUND

The U.T.F. shafts are 3.0 m in diameter. The anticipated size of the drilling machine will require it to be disassembled for lowering into the mine. An equipment assembly station with overhead crane will be installed at the bottom of the No. 2 shaft to facilitate re-assembly of the equipment (Figure 2).

) TRANSPORTATION SERVICES

derground transportation will be provided by conventional mining equipment such as bber tired, diesel powered vehicles. The selected équipment will be "Approved" to eet Provincial Safety Regulations and will be used to remove drill cuttings and carry pplies to the drill, i.e. lubricants, cement, etc. as well as to transport well completion rdware and drill pipe. The equipment will include vehicles with specially designed rrying capacity and lifting devices (see Figures 3a and 3b). It will also be necessary provide auxiliary vehicles such as drill pipe and liner carriers.

0 VENTILATION

rill sites will be situated in well ventilated tunnels (see Figure 4). It is expected at any gases which occur will be from the oil sands, in which case the most abundant ill be methane and carbon dioxide. It has been assumed that hydrogen sulphide may e present in small quantities. Any gases from the well will be swept away down tream. Gases released from the drilling fluid and cuttings at the de-sander will be afely dissipated into the return air-stream by releasing the exsolved gases inside a entilated safety cage.

he air at the drill site will be constantly monitored to record gas concentrations. isual and audible warning signals will operate if pre-determined safe levels are xceeded. Methanometers will electrically isolate the drilling equipment, if the methane ontent of the air exceeds acceptable safety levels.

6.0 UTILITY SERVICES

Compressed air will be piped to the drill site from surface compressors. If extra high pressure air is needed, it can be supplied by an underground, booster compressor. Water will be available at pressures and quantities suitable for firefighting and mud mixing etc.

Electricity supply to the drill site will include the use of Approved, Flameproof, dry type, mining transformers. Electrical switch gear and motors will be of a type approved by the Department of Occupational Health and Safety; in general terms, this means equipment that conforms to the standards established for coal mines. Electrical apparatus will include lighting and telephone communication.

7.0 GENERAL SAFETY

The Mining Engineer will undertake the tasks of:

- liaison with the Department of Occupational Health and Safety
- advising on the special design features necessary for underground equipment, i.e. flame resistant hydraulic fluids, non-use of exposed light alloy parts, lighting standards etc.
- providing underground safety measures such as bulk head fire doors, respiratory equipment, gas detectors and mine safety examinations.

Jointly, the Mining Engineer and Drilling Engineer will prepare Codes of Practice for the safe operation of the drill and its associated equipment. This will include, as a minimum the following:

- Authorization of persons to operate the equipment
- Use of the B.O.P.'s
- Authority and responsibility of appointed supervisors
- Recognition of signs of malfunction of equipment or impending dangers
- Use of safety devices, including personal protective equipment
- Actions to avert dangerous occurrences
- Warnings and alarm signals and the response action required from persons at the work site

The Codes of Practice will undoubtably require modification in the light of experience. However, their preparation in the first instance will be preceeded by a hazard analysis of the complete drilling activity. By following this procedure the drilling operation can, in the authors' opinion, be conducted in a safe and efficient manner.

8.0 THE DRILL

The drill must be capable of drilling from mine tunnels which may be located in either the tar sands or in the limestone beneath the tar sands. In addition, it must be able to place wells in the closely spaced configurations that production methods may require.

Drilling from a tunnel in the limestone, requires that holes be drilled on the upslope, through the limestone and deviated to horizontal several meters above the base of the tar sands after which drilling would continue horizontally for the remaining length of the well.

Among the well patterns that may be required, the most exacting is, perhaps, the proposal to drill dual wells, one placed several meters above the other. The upper hole would be used as a steam injector and the lower one for production.

Since the drill should be capable of handling drilling tools longer than the width of the tunnels it is proposed that these "long-tools" be placed in a "mouse-hole" drilled in the opposite side of the tunnel. The tools could then be inserted into the hole by the drill (see Figure 6). The drill must be equipped with a pipe handling device to manipulate the drill tools, drill pipe and casing within the confines of the mine tunnels.

No underground drills are available that meet all the requirements for such a specialized duty, consequently it is to be designed and developed by Drill Manufactures working closely with drilling and mining engineering personnel.

The drilling programme will require that a conductor hole be drilled for several meters and conductor pipe be cemented in place. A control head will be attached to the conductor pipe to control any flows of fluid that may be encountered while drilling the surface hole. Next the surface hole will be drilled and surface casing cemented in place. After the control head is attached to the surface casing the main hole will be drilled. The wells could be completed by installing a slotted liner in the hole or by running and cementing production casing as in conventional wells. The cementing and perforating of a production string would require that special tools and methods be developed.

The drilling limits regarding diameter and hole lengths will be explored in tests to be conducted at a surface outcrop site and later at the Underground Test Facility.

9.0 THE PRESSURE CONTROL SYSTEM

Gas and water under pressure may be encountered in the base of the oil sand. Provisions will have to be made to safely contain gas and water flows so that they cannot enter the mine tunnels in a uncontrolled and dangerous manner. To do this, light-weight, low pressure, easy to handle blow-out preventors (B.O.P.'s) will have to be designed and manufactured. Most of the existing B.O.P.'s are for oilfield use at high working pressures and are very heavy and cumbersome.

Since the underground drilling situation is the reverse of a normal vertical well; the underground horizontal wells will not have the advantage of hydroctatic head to contain the formation pressures in the well bore. The possibility of water and gas pressures requires that drilling and completion operations will have to be conducted under "packed-off" conditions with "Pack-off" heads capable of controlling the well while:

drilling,
making connections,
surveying,
tripping,
logging,
running casing,
perforating and while running tubing and completion tools.

10.0 DRILLING THE MAIN HOLES (See Figure 7)

In order to maintain directional control of the hole while drilling, it will be necessary to run some type of steerable assembly. The most commonly used system in the oil and mining industries is a down hole mud motor and a bent sub assembly. Using this method the bit can be oriented by turning the bent sub with the drill pipe to the desired direction. The drill pipe is not allowed to rotate once the bent sub has been oriented. Drilling ahead is then accomplished by rotating the bit only using the mud motor. The well can be surveyed at any time and corrections to the direction of the hole can be made by re-orienting the bent sub. When the hole is on course the drill pipe is allowed to rotate slowly so that the influence of the bent sub is distributed circumfrentially around the axis of the hole. Any deviation is then effectively negated by the slow rotation of the pipe. The angle of the bent sub, one to two degrees, is small enough that it does not create a problem in the hole when being rotated but is large enough to correct or change hole direction when it is held stationary in any one direction.

11.0 SURVEYING METHODS

A magnetic instrument combined with an accelerometer has proved to be a reliable method of surveying for directional control. Measurement while drilling, (MWD), which uses pressure pulses of the drilling fluid, is a fast and accurate method of relaying directional information from the bit back to the drillers. However, when these systems are used to survey horizontal wells drilled in pairs, as processing schemes may require, two problems arise:

1. The magnetic instrument will give good readings on the first well but once its steel casing has been placed, it will influence the magnetic readings in the second well. A solution to the magnetic problem, is to drill both holes before attempting to run the casings. This may not be a viable solution since the first well may cave or collapse before the second well is drilled.
2. The mud pulse relay relies on good hydraulic transmission and a mud flow that is continuous and free of air spaces. This will probably not be the case in the proposed well due to its being drilled on an up-slope to horizontal profile. Drilling fluid will drain from the bore hole since the pumps must be shut down while mud pulse readings are taken.

Two non-magnetic survey methods are being investigated. The first operates on a surface survey system that picks up signals sent out from a transmitter placed near the bit. The signals are computerized to give a continuous read out of the position of the bit.

The second method uses gyroscopic survey instruments. This type of instrumentation is currently being evaluated to determine, first, whether it can give the degree of accuracy needed to drill parallel holes and second whether it is of a sufficiently robust construction to avoid damage during use.

12.0 RUNNING AND CEMENTING SURFACE CASING

Since steam is to be injected into the wells during processing it is imperative that a continuous and competent cement sheath surrounds the full circumference of the surface casing, especially at the tunnel or collar end. A poor cement job could allow steam to escape into the tunnels requiring an entire group of production cells to be shut down while the steam pressure is bled off and repairs made to the defective well.

The running and cementing of the surface casing in upslope/horizontal wells requires new methods and equipment be developed. It is proposed to equip the casing with swirl fins so that rotating the casing in the hole during placement of the cement will ensure that the cement is evenly distributed to seal the annulus around it.

Special centralizers must be developed that will support the full weight of the casing and prevent it from lying along the bottom of the hole; they must also slide along the the hole as the casing is being pushed into place, yet allow the casing to be rotated as the cement is being placed to fill the annulus. A special cement "pack-off" will have to be designed for the collar or tunnel end of the casing which will permit, cement to be pumped into the annulus while the casing is being rotated (see Figure 8).

13.0 RUNNING A SLOTTED LINER UNDER PRESSURE

To run a slotted liner into the hole under pressure, it will be necessary to use a dual pack off head as shown in Figure 9. An outer casing string will be run in the hole using a bit to clean out any hole cave-ins; a check valve to prevent fluids from blowing out through the casing; an anchor to hold the inner slotted liner in position while the outer casing is tripped back out of the pressurized hole; and a back off joint to release the outer casing from the anchor.

14.0 RUNNING WIRE LINE TOOLS

Wire line tools can be run into the hole through drill pipe, tubing or casing. The tools can be pumped into the hole provided there is an annulus for return fluid flow; they can be pulled from the hole by the wire line. It may be necessary to maintain a positive pressure on the tools by means of pumps in order to prevent them from being blown out of the hole.

Running wire line tools into an uncased hole under pressure would necessitate the use of a specially designed dual "pack-off head so that the tools can be pushed into the hole allowing both the wire line and the pusher pipe to be "packed-off" (see Figure 10).

15.0 THE MUD SYSTEM (See Figure 11)

The mud system will likely be similar to oilfield type mud systems with special provisions to separate gas and solids from the drilling fluid. The major consideration is whether to design the system to be placed in the mine tunnels underground or to provide for a central system above ground. The above ground system would require a fairly long pipeline to circulate the mud to the surface but it has the advantage of bringing all of the gas and cuttings to a surface location where they can be dealt with safely in a single operation.

The underground system would require extra space in the mine tunnels and a sufficient volume of air to dilute the gas to safe limits.

16.0 SUMMARY

While most of the technology and equipment to drill underground wells is available, considerable innovation and modification will be required to adapt the technology to drilling upslope/horizontal wells. The areas that require new technology and equipment are:

- the drill itself,
- pressure control equipment,
- methods of running and cementing casing and
- a non-magnetic direction surveying system that is fast and reliable.

The authors believe that by adapting present technology, 114 mm casing can be placed in 800 meter horizontal holes. With experience and as techniques are developed, longer, larger diameter holes, should be attainable at an acceptable cost.

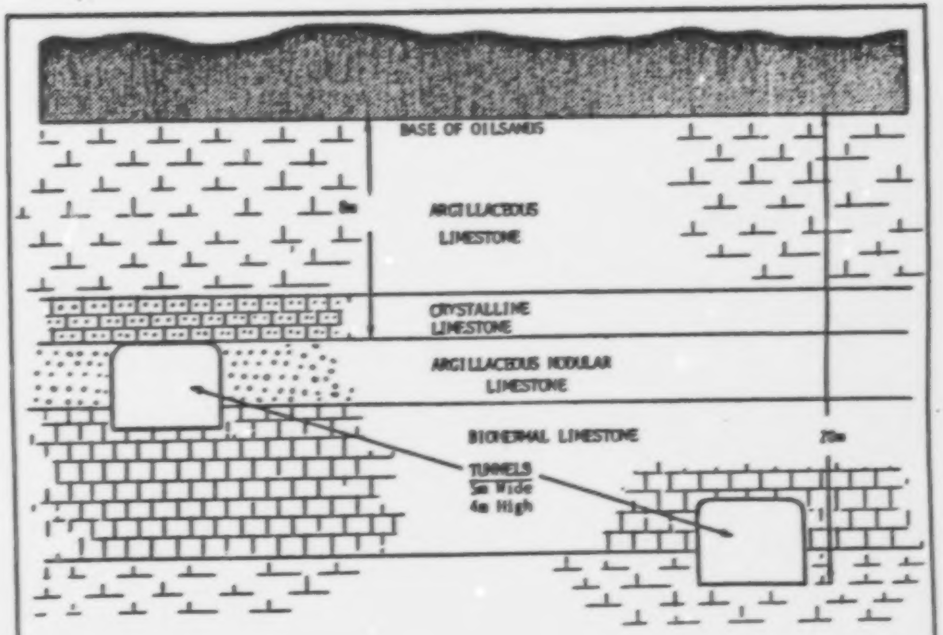
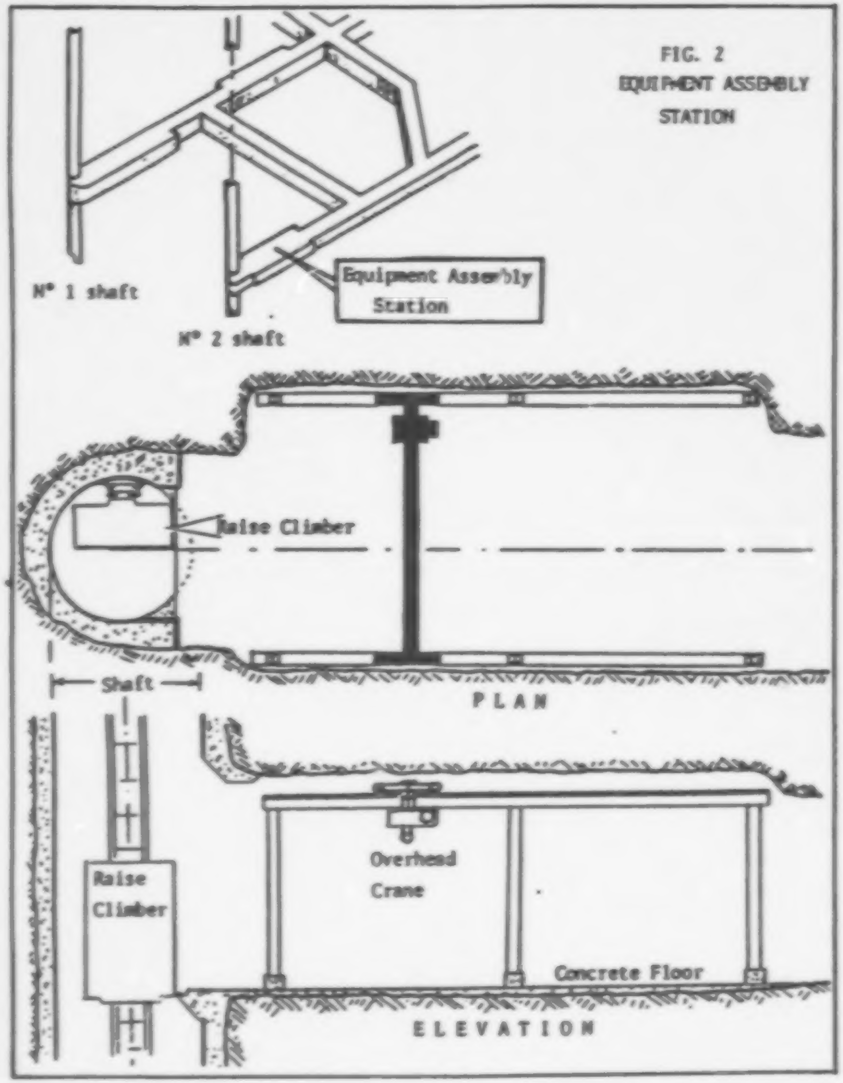


FIGURE 1

FIG. 2
EQUIPMENT ASSEMBLY
STATION



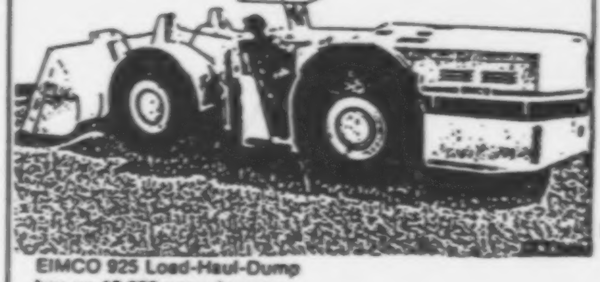


Fig. 3a

EIMCO 925 Load-Haul-Dump has an 18,000-pound carry capacity — the largest payload for this size machine in the industry. Optional bucket sizes are available to suit application requirements. Designed for superior fuel economy and performance, the machine's seven-foot width allows operation in narrow drifts — providing high maneuverability in tight underground environments.

This maneuverable, low-profile, surefooted, hydraulically-powered tractor is primarily designed for removing, transporting and positioning longwall supports and conveyors. But it's also great for lifting, erecting and loading equipment underground. The most common use of the Mule is to skid a load. It will lift over 12 tons and skid over 18 tons.

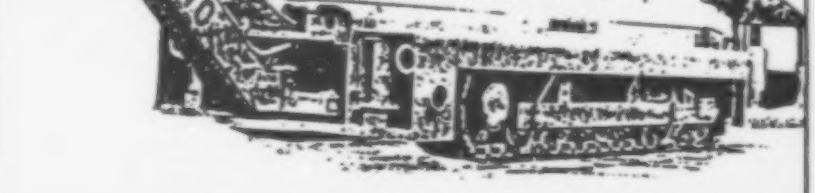
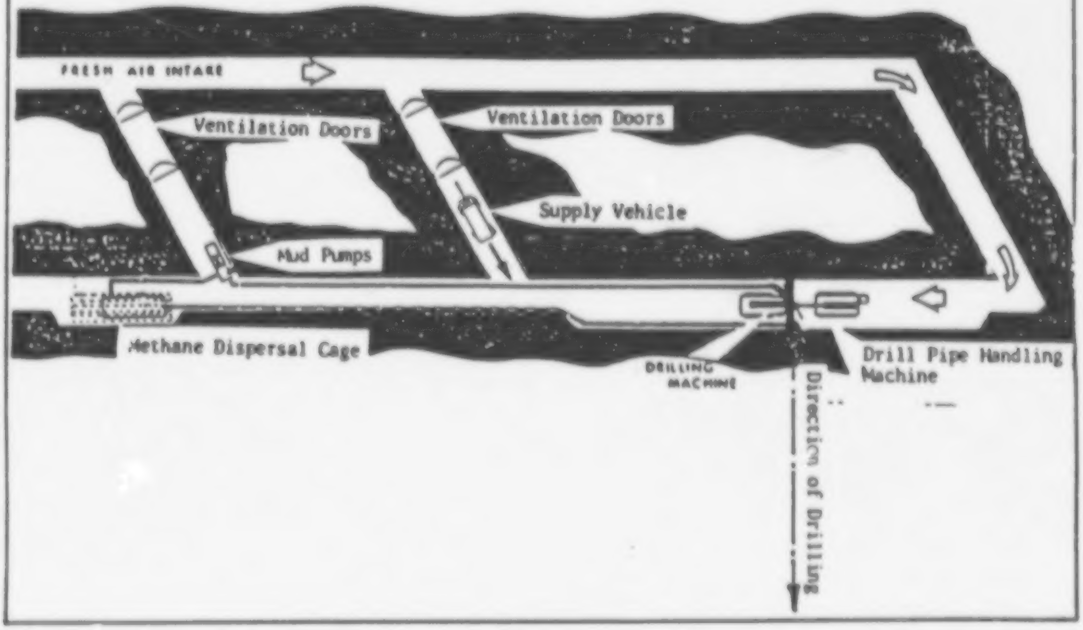
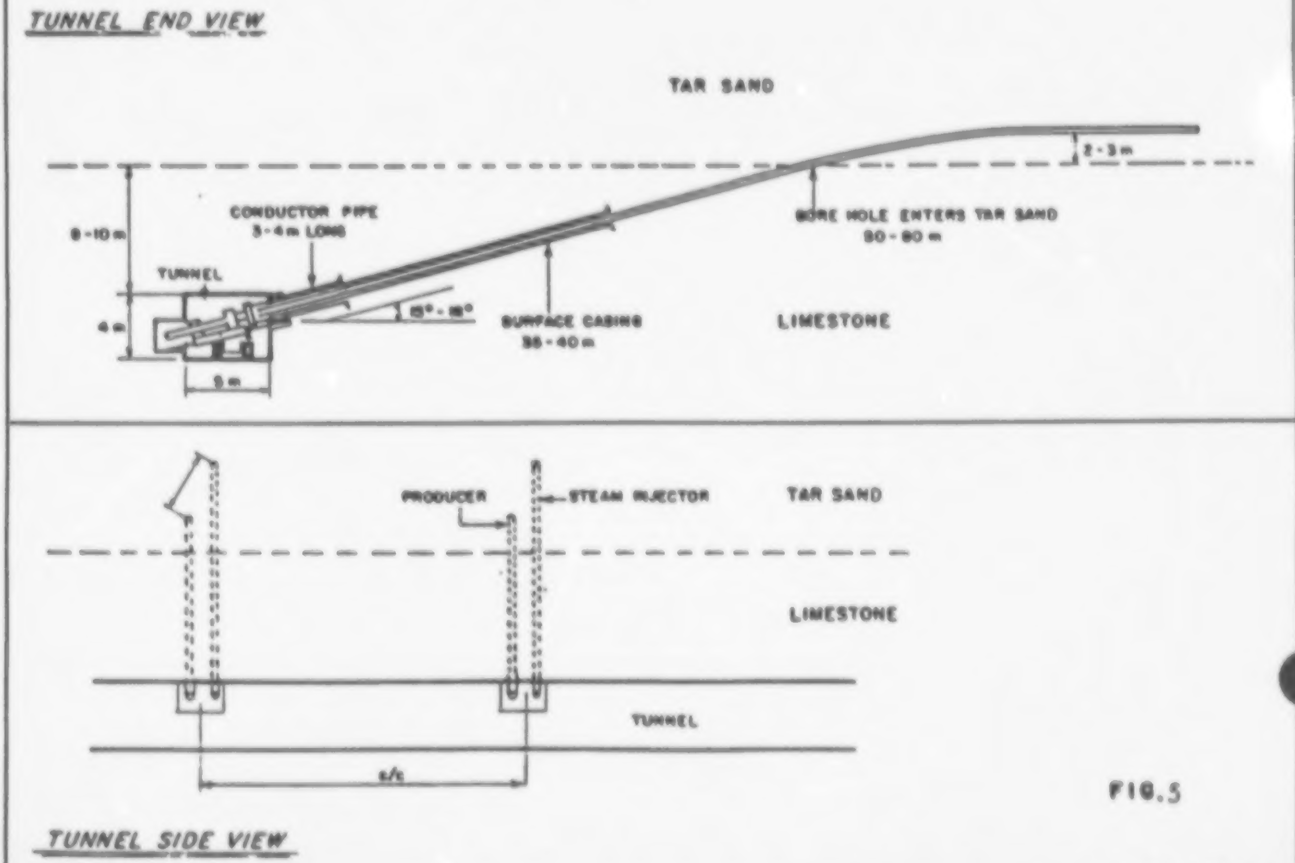


Fig. 3b

FIGURE 4

LAYOUT OF DRILL SITE




TUNNEL END VIEW

TUNNEL SIDE VIEW

FIG. 5

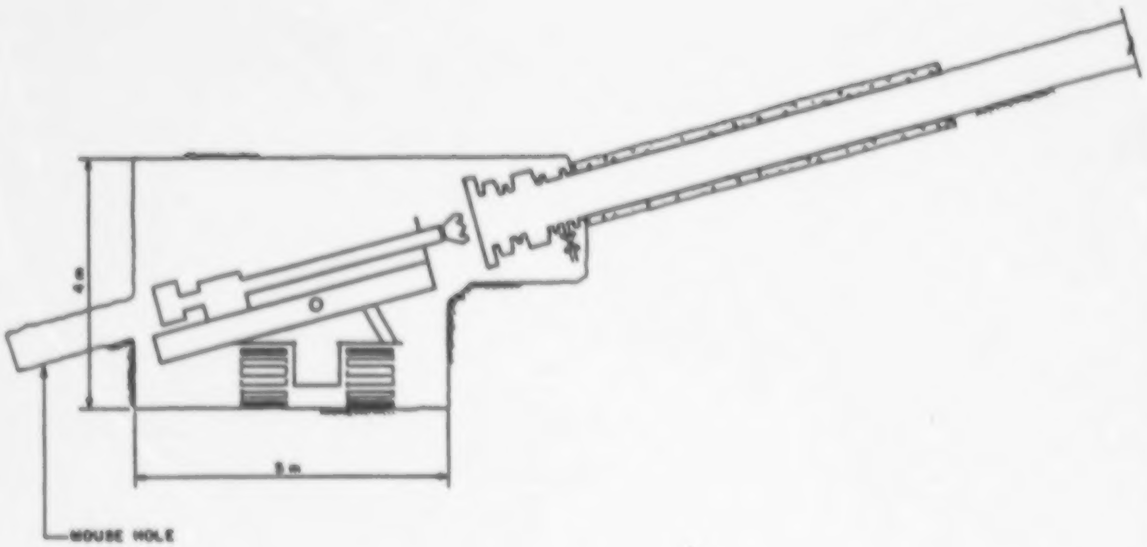


FIG.6

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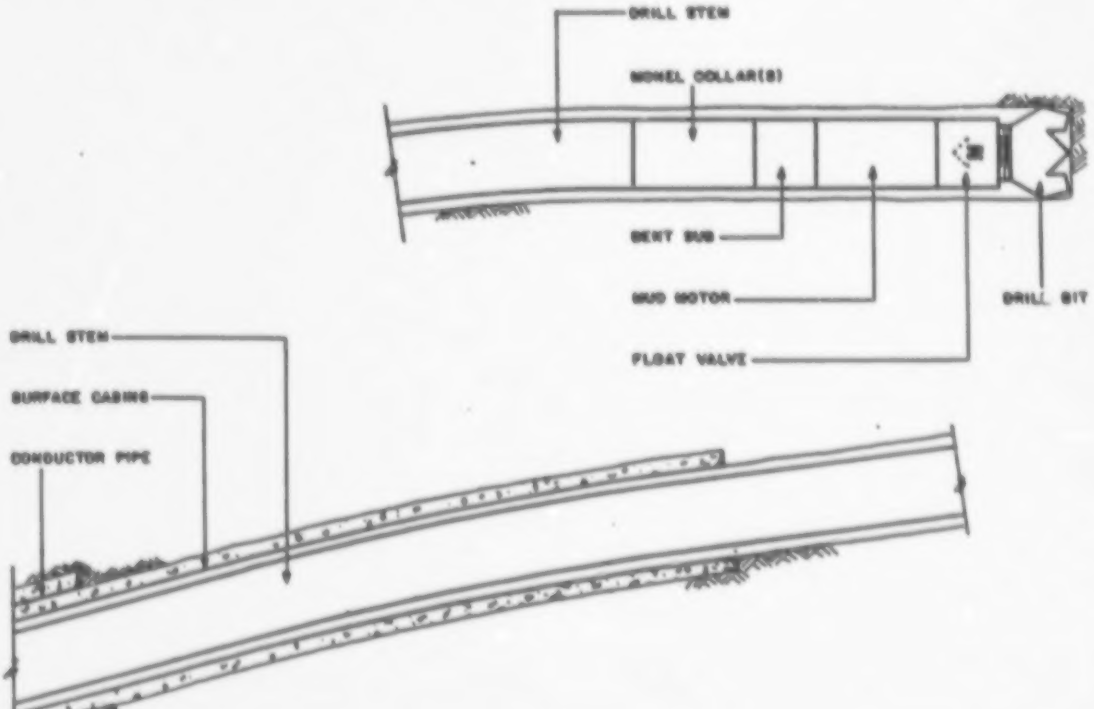

FIG.7

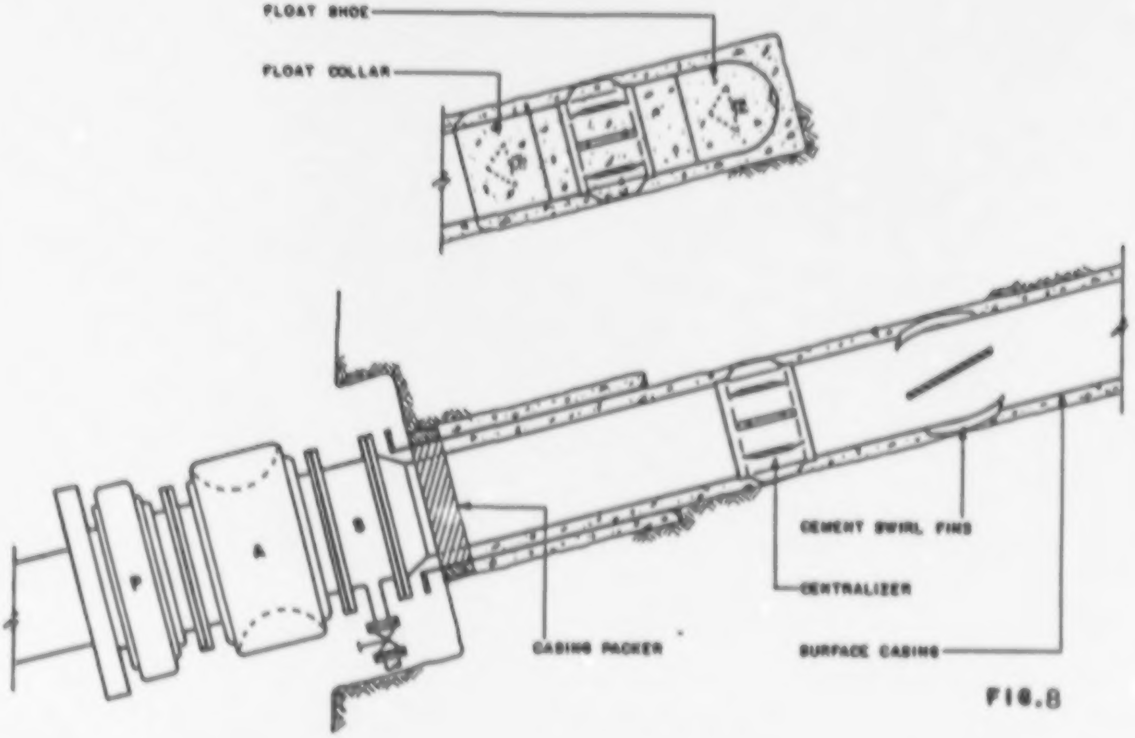

FIG.8

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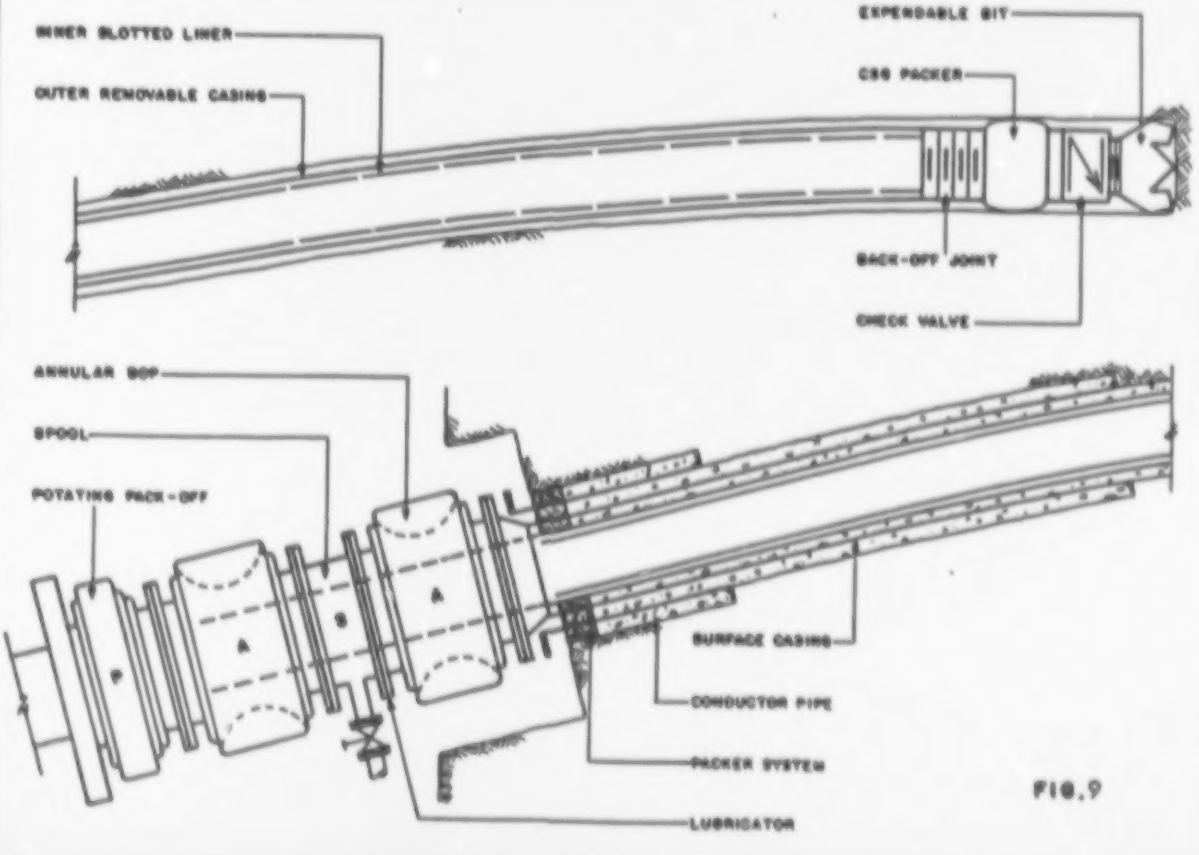

FIG.9

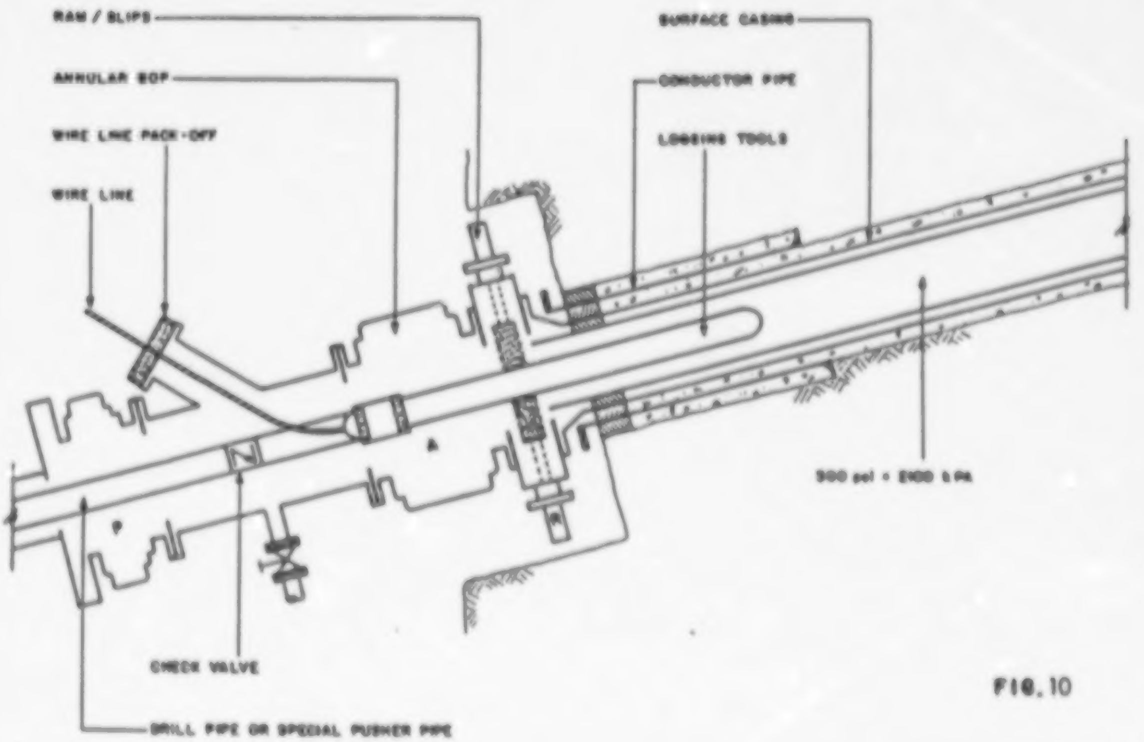
RAM / SLIPS
SURFACE CASING
ANNULAR BOP
CONDUCTOR PIPE
WIRE LINE PACK-OFF
LOGGING TOOLS
WIRE LINE
A
P
500 psi = 3400 kPa
CHECK VALVE
DRILL PIPE OR SPECIAL PUSHER PIPE
[illegible] ENGINEERING LTD.

FIG. 10

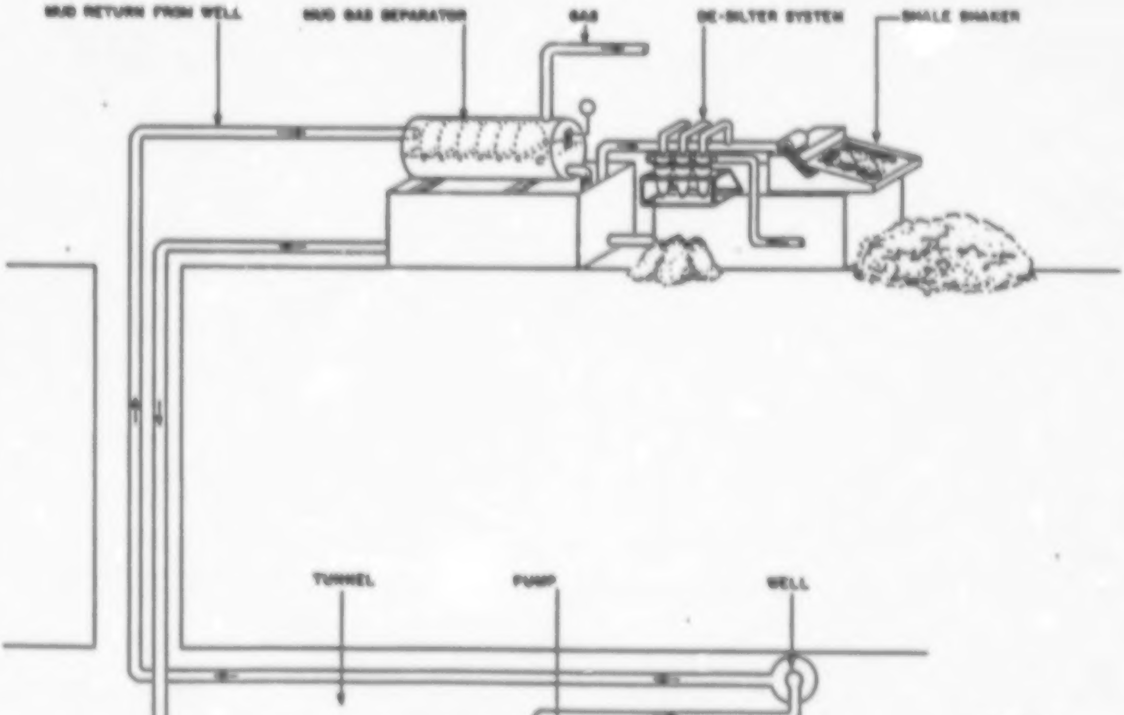
MUD RETURN FROM WELL
MUD GAS SEPARATOR
GAS
DE-SILTER SYSTEM
SHALE SHAKER
TUNNEL
PUMP
WELL
[illegible] ENGINEERING LTD.

FIG. 11

010488

THIRD INTERNATIONAL CONFERENCE ON HEAVY CRUDE AND TAR SANDS

LONG BEACH,
CALIFORNIA
22-31 JULY 1985

Alberta OIL SANDS
INFORMATION CENTRE

(60)

VOLUME II

942

HCTS/CF.3/11.6

(NOT FOR PRESENTATION)

THIRD INTERNATIONAL CONFERENCE ON HEAVY CRUDE AND TAR SANDS
TERCERA CONFERENCIA INTERNACIONAL SOBRE CRUDOS PESADOS Y ARENAS BITUMINOSAS
TROISIEME CONFERENCE INTERNATIONALE SUR LES PETROLES LOURDS BRUTS ET LES SABLES BITUMINEUX

PROGRESS REPORT ON THE CONSTRUCTION OF AN UNDERGROUND TEST FACILITY IN THE ATHABASCA DEPOSIT, ALBERTA, CANADA

BY

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INTRODUCTION

Since 1975, the Alberta Oil Sands Technology and Research Authority (AOSTRA) has been investigating many methods of recovering bitumen from the vast reservoirs of oil sands in Alberta.

The in situ methods which AOSTRA has examined have generally involved operations aimed at reducing the viscosity of the bitumen and causing it to flow to production wells where it can be pumped to the surface. These methods have been dependent on vertical wells drilled from the surface to inject the fluids and recover bitumen.

In the late 1970s, AOSTRA began to investigate the use of horizontal or semi-horizontal wells drilled, not from the surface, but from tunnels constructed either in the vicinity of the reservoir or even within the pay zone for in situ recovery of bitumen. The concept utilizes mining techniques to construct shafts and tunnels, but does not recover any oil sand by mining, and enables personnel and equipment to operate from within or close to the reservoir. The idea is known as the "Shaft and Tunnel Access Concept" (SATAC) and AOSTRA believes this concept has potential for recovering an increased percentage of the bitumen in place. The alternative technique of placing horizontal wells from the surface has been called the "Surface Access Concept" or SAC and is being pursued independently by a number of oil companies. Figure 1 shows both the SAC and SATAC concepts.

PRELIMINARY INVESTIGATIONS

AOSTRA has been involved in several investigations to examine the application of the SATAC concept. During 1976-77, a team of Canadian representatives visited the Yarega operation in northern Russia where a heavy oil reservoir has been exploited by an in situ steam process applied through wells drilled from tunnels. The Russians have stated that thermal stimulation from underground tunnels has increased the recovery of oil in place from 10 to 57%. An evaluation of Mine Assisted In Situ Processes (MAISP) was carried out in 1978, by a consortium of oil companies to assess its applicability to the Alberta oil sands, with encouraging results.

Later, AOSTRA combined with Gulf Canada Limited to investigate the application of horizontal wells at Surmont in the Athabasca oil sands. This two-year assignment was designed to compare the comparative economics of the SAC and SATAC approaches (Horkoff, 1984).

Other investigations of a similar nature continue to be carried out by Esso Resources Canada Limited and a group of oil companies headed by Petro-Canada Limited (Smith and Butler, 1981; Towson, 1984; Quinn and Duncan, 1981).

944

LIMITATIONS OF THESE INVESTIGATIONS

All those investigations that examined the technical and economic feasibility of SATAC identified the potential for greater recovery of the reserve using the SATAC approach. However, in each case, the validity of the conclusions reached was dependent upon a series of assumptions as to:

- the cost of constructing shafts and tunnels and of drilling and completing horizontal wells:
- the parameters for, and performance of, in situ processes in closely-spaced horizontal wells in oil sands.

The credibility of the conclusions has remained open to question on three counts:

- Firstly, there is no experience of constructing shafts through the overburden to the oil sands, or of driving tunnels in the oil sand or adjacent strata.
- Secondly, while underground drilling technology has advanced considerably, there is no experience of drilling and completing high pressure thermal horizontal wells in oil sand from tunnels.
- Thirdly, while some data is available on in situ operations from horizontal wells drilled from the surface, the parameters for, and performance of. in situ processes in oil sands applied through horizontal wells drilled from tunnels, are unknown.

It was clear to AOSTRA that further studies based on similar assumptions were unlikely to provide information which could justify construction of even a small-scale commercial SATAC operation. If the very significant potential advantages of a SATAC system were to be established and confirmed for application in a commercial operation, "hands-on" mining and in situ processing experience in an underground environment was vital. Without the hard data, economic and technical feasibility evaluations are not possible.

THE PROBLEM

Some of the uncertainties in applying the SATAC concept, about which assumptions have had to be made in past studies and investigations, are listed below.

Major Mining Related Uncertainties

a) The effect of various geological/geotechnical parameters on construction of shafts and tunnels in the oil sands and adjacent strata.
b) The preferred horizon for tunnel construction and the type of support and/or lining needed.

c) The behavior of oil sands at the face and perimeter of tunnels driven in the pay zone.
d) The rate of gas emission from exposed oil sands, the types of gas encountered, and the extent of mine ventilation problems.
e) The difficulty involved in protecting the tunnels and shafts against steam pressures and stresses resulting from the application of thermal in situ processes.
f) Costs for the development of shafts and tunnels.

Major Process Related Uncertainties

a) The spacing, length, and alignment of injection and/or production wells for optimum recovery of bitumen.
b) The quantity and pressure of steam required for optimum bitumen recovery.
c) How the use of horizontal wells from tunnels compares in cost with in situ operations from surface accessed wells.
d) The complexity of drilling, completing, and servicing horizontal wells from tunnels.
e) Determination of reservoir characteristics which favor in situ operations using horizontal wells.
f) The protection of underground operators and facilities against well "blow out", particularly if high pressure steam is involved.

THE NEED FOR AN UNDERGROUND TEST FACILITY

Clearly, if answers were to be provided to the questions posed above and meaningful comparisons with surface access systems made, an underground facility had to be constructed to test mining, drilling, and in situ systems specifically suited to the conditions encountered in the Athabasca oil sands. The facility could also be used as an underground laboratory to determine the mass properties of oil sands under reservoir conditions and observe directly the effects of various recovery techniques. Consequently, in December 1982, AOSTRA retained a Calgary consulting company to prepare a conceptual design for an underground test facility.

The consultant was asked to:

- Design the access phase of the facility
- Prepare requests for proposals for construction of the access phase
- Prepare applications for regulatory approvals
- Provide detailed capital cost estimates
- Collect geotechnical data on the site conditions

The next section of this paper described the planning and engineering of the access phase of the Underground Test Facility (UTF).

PHASING OF DEVELOPMENT

It was decided that the UTF, as it came to be called, would be designed and constructed in three phases.

Phase One (the Access Phase) would include vertical shafts, a pit bottom, sufficient tunnel to allow the drilling equipment to be tested, and a short experimental tunnel to be driven in oil sand.

Phase Two (the Drilling Phase) would involve the design, construction, and testing of the drilling equipment for horizontal wells.

Phase Three (the Pilot Phase) would include the design and construction of tunnels and surface facilities, and the drilling of horizontal wells, to allow in situ processes to be piloted.

SITE SELECTION AND ACCESS

A site was selected in Tp. 93, R-12 W4M, 44 km northwest of Fort McMurray following exploration programs designed to collect geological and geotechnical data on the McMurray formation, the overburden, and the Devonian limestone below the reservoir. The site selected (Figure 2) has the following characteristics:

Overburden -- 91.4 m thick or greater
Pay zone -- 19.6 m average thickness
Bitumen -- 13.76% average by weight
Reserves -- 325 million barrels of bitumen in place

A temporary road was constructed during the winter of 1983-84 for exploration work on the site.

DESIGN OF THE ACCESS PHASE

The initial step in designing the access phase was to decide whether one or two shafts were required and to determine the shaft diameter(s). The duty of the shaft system was specified as follows.

Ventilation

The shaft system was to be capable of circulating enough fresh air to dilute the methane and any hydrogen sulfide emissions which might be encountered. This was considered to be a worst case situation for a pilot since a more likely scenario is for the tunnels to be in limestone rather than oil sand. The design air quantity is sufficient to provide cooling of the tunnels during a limited thermal pilot operation.

Materials Handling

It was decided that a skip cage combination capable of hoisting 100 tonnes of waste per hour from tunnels would be sufficient.

Equipment Transportation

The shaft system would require the capacity to transport tunneling and drilling equipment, broken down as necessary, to the pit bottom. The system must also be capable of handling pipes of suitable lengths for steam and product transport in the tunnels.

Access to Tunneling Horizon

A shaft depth of 223 m was selected, with an inset at 173 m providing access to the main tunneling horizon in limestone.

SELECTION OF SHAFT CONFIGURATION

In addition to the parameters mentioned above, other factors which were taken into account in selecting the shaft configuration included:

- the security and safety of personnel working in the UTF;
- the proportionately high cost of shaft construction, particularly for a pilot-scale facility;
- the comparative technical advantages of the methods of shaft construction considered: namely blind shaft boring and freezing and excavating.

It was concluded that two shafts, each with a finished diameter of 3.0 m, should be sunk for the underground test facility.

SELECTION OF SHAFT CONSTRUCTION METHOD

Shaft sinking had not previously been carried out successfully through the oil sands. Geotechnical investigations had shown that the properties of the strata through which the shafts were to be sunk would determine the shaft construction method. The strata consisted, in descending order, of soft, weak, clayey, and silty deposits, the oil sands themselves, and the Devonian limestone below the reservoir. Characteristics of the strata which caused most concern included:

- the presence of swelling clays and very weak materials in the formations above the oil sands;
- the slabbing of oil sand when a free face is exposed, believed to be caused by exsolution of gas.

Only two methods of construction were considered worthy of serious consideration. These were:

- Blind shaft drilling
- Freezing and excavating

Detailed examination of these two systems was completed and blind shaft drilling was chosen. This method is similar to the drilling of vertical oil wells except that the bit assembly and drill pipe are much larger and the drilling rig is utilized, not only to drill the shaft, but also to place the liner. Mud is utilized to support the walls of the shaft and to carry cuttings to the surface. In this particular case, the mud pressure was expected to minimize exsolution of gas from the oil sand and prevent sloughing of the shaft wall. A further advantage was that no personnel would be in the hole during construction and lining operations.

SHAFT LINER AND EQUIPMENT

The layout and equipment of the two shafts is shown in Figure 3. The arrangement shown provides all the essential mine and other services for a small-scale pilot operation at minimum expenditure.

No. 1 shaft is utilized for intake ventilating air and accommodates the skip cage and a manway. No. 2 shaft will be the return air shaft and will provide for emergency hoisting. All pipelines for steam, bitumen, etc., will be in the No. 2 shaft.

Both shafts will be equipped with a steel liner having an internal diameter of 3.03 m and capable of withstanding hydrostatic and ground swelling pressures. The liner will be constructed from steel plate. Each liner section will be equipped with stiffener rings and grouting pipes on the outside, and equipment rings welded on the inside.

MAIN HOIST

An electrically-powered single-drum hoist and a head frame will be installed at No. 1 shaft to handle the skip cage.

UNDERGROUND LAYOUT

The layout of the underground tunnels is still in the planning stages. Only the immediate area of the shaft bottom has been planned in detail.

Figure 4 shows a conceptual layout for the Access Phase of the test facility which provides a service area at the base of the shafts with accommodation for equipment assembly, rock handling, pumping, and a refuge chamber in case of emergency. This layout also shows test chambers for carrying out horizontal drilling tests from tunnels in limestone and oil sands during the Drilling Phase. This layout is shown for illustration only and is subject to revision.

All tunnels will initially be driven in the limestone with between 8 and 15 m of solid rock between the roof of the tunnel and the base of the sands. Tunnels may be driven on two levels with the upper tunnels being used for drilling and completing wells and lower tunnels for personnel and equipment access.

Consideration is being given to drivage of a test tunnel in oil sands. Recognizing that this is potentially a more hazardous location, the data are, however, required for comparative economics.

The tunnels needed to develop the first in situ pilot will extend for approximately 1 km from the shaft. Tunnels will generally be 4 m high and 5 m wide supported by rock bolts and shotcreted to prevent weathering of the strata. They will be driven by road heading machines to provide a smooth and unfractured tunnel perimeter.

The layout and engineering of the pilot phase tunnels will be finalized late in 1985.

SAFETY

Detailed evaluation of the hazards likely to be encountered and of the security measures required is being done continuously. This evaluation is focusing particularly on ventilation, strata control, and hazards resulting from the drilling of wells and the use of in situ processes in underground tunnels. Codes of practice and operational procedures are being developed to ensure the facility is as secure as experience and modern technology will allow.

CONSTRUCTION OF ACCESS PHASE

The engineering and capital costing of the Access Phase was finished in January of 1984. In June of 1984, AOSTRA made the decision to go ahead with construction of the Access Phase, to commence design of the drilling equipment, and to engineer the Pilot Phase.

Norwest Resource Consultants Limited was retained to act as Project Manager and Owners Representatives on site. The Harrison/Saturn joint venture was selected as general contractor and they in turn selected the Simmons/Santa Fe joint venture to construct and line the two shafts.

No. 2 shaft was spudded on February 14, 1985. After some problems with a highly plastic clay zone near the surface, the operation proceeded smoothly and the shaft drilling was completed in 55 days at an average rate of 3.8 m per day. The shaft was caliperred and surveyed and was found to have deflection of less than 0.2 degrees and no wall sloughing of any consequence. The liners were installed in the shaft and grouted in position in April 1985.

Drilling of No. 1 shaft began in April and it is expected that, if all goes well, the shafts, pit bottom, and support facilities will be completed in April 1986. Figures 5, 6, and 7 are photographs taken during construction of No. 2 shaft.

THE PILOT PHASE

Engineering of the Pilot Phase has begun. This includes:

- the detailed evaluation of various in situ processes and the selection of a system or systems for piloting;
- the design of the surface facilities and underground mine layout for the pilot;
- the design, fabrication, and site testing of the horizontal well drilling equipment.

A steering committee consisting of industry representatives is assisting AOSTRA in the selection of in situ processes for the Pilot Phase.

SCHEDULE

Provided construction of the Access Phase goes according to plan, the schedule for construction of the Underground Test Facility (Figure 8) pilot operations should begin in mid-1987.

CONCLUSION

In favorable circumstances, the use of closely spaced, parallel wells, drilled from tunnels close to the reservoir, should result in higher recovery, more efficient energy utilization, and lower production costs than vertical or horizontal wells drilled from the surface.

The Underground Test Facility will provide operators with the opportunity to conduct in situ process testing and bitumen recovery schemes which benefit from the SATAC approach. This in turn could lead to successful development of economically viable commercial operations in oil sands buried more than 100 m below the surface.

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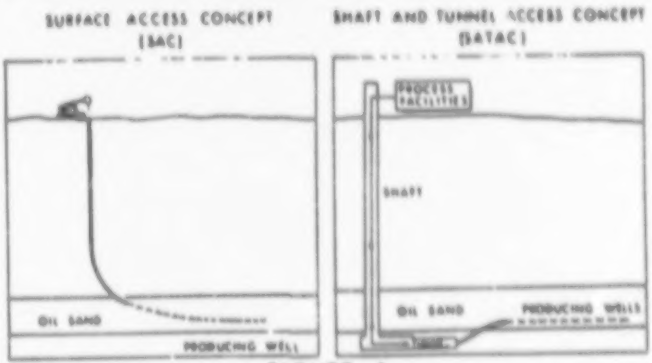


FIGURE 1
IN SITU OPERATIONS THROUGH HORIZONTAL WELLS
SAC AND SACTAC CONCEPTS

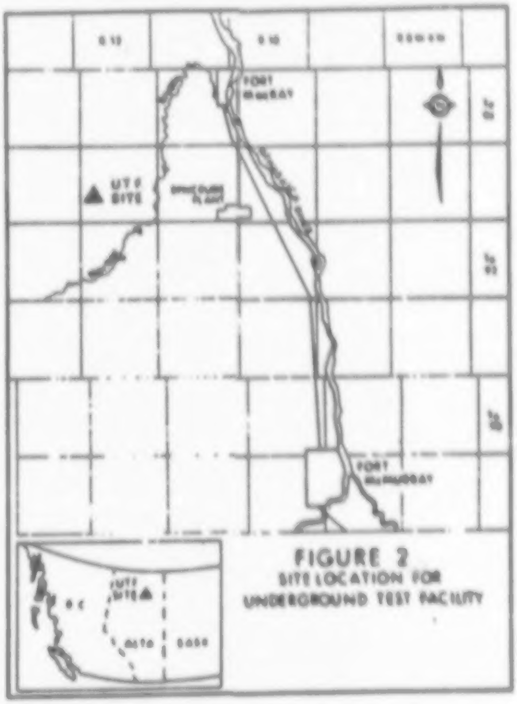


FIGURE 2
SITE LOCATION FOR
UNDERGROUND TEST FACILITY

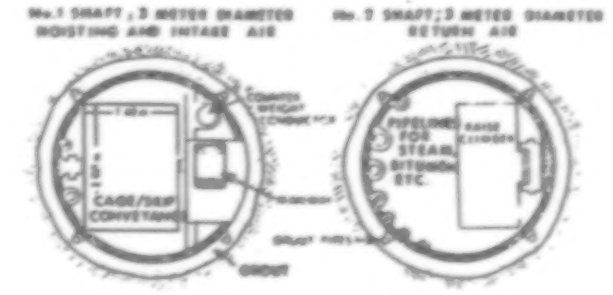


FIGURE 3
PLAN VIEW OF SHAFTS SHOWING
EQUIPMENT DISPOSITION AND VENTILATION DUTY

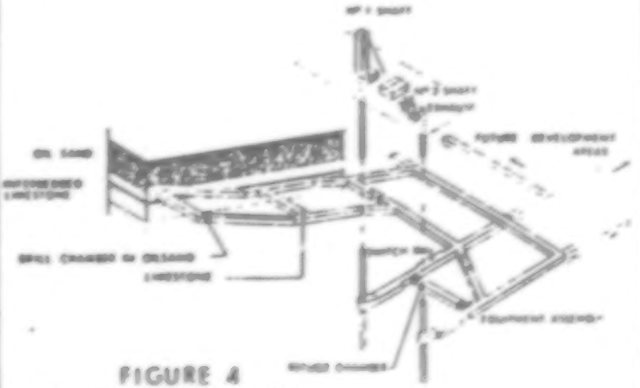


FIGURE 4
ISOMETRIC SCHEMATIC OF SHAFT
AND
TUNNEL LAYOUT FOR PHASE ONE

FIGURE 5

DRILLING IN PROGRESS

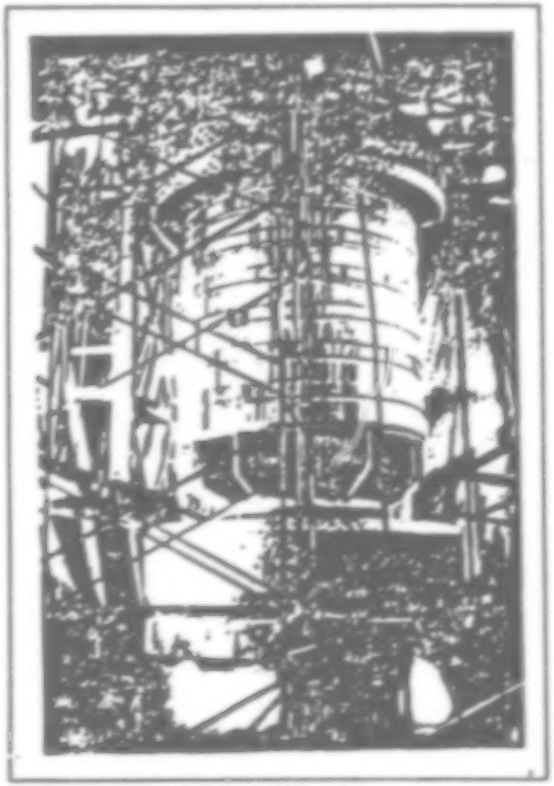


FIGURE 6

COMPLETE DOWNHOLE ASSEMBLY

At the bottom, the Cutting Bit; above the bit, the downhole weights; at the top, an upper stabilizer. Total assembly weighs 227 thousand kg. (500,000 lbs.), it is supported by a dual wall, drill string 340 mm diameter (13 3/8").

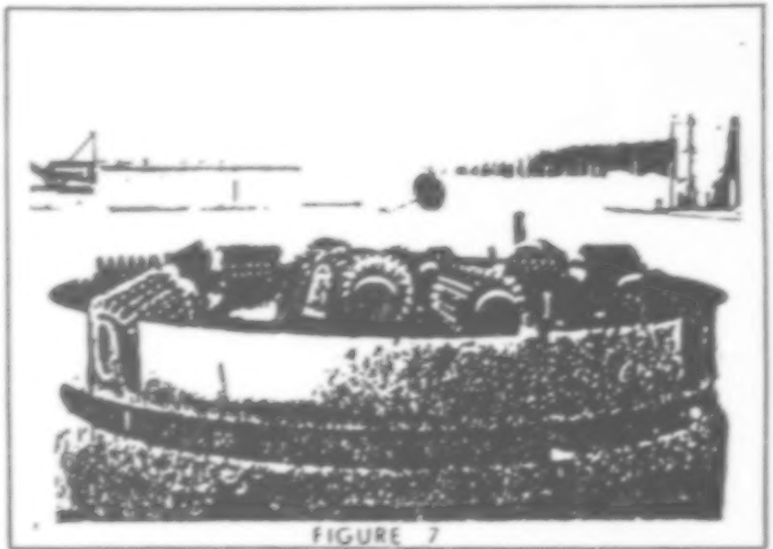
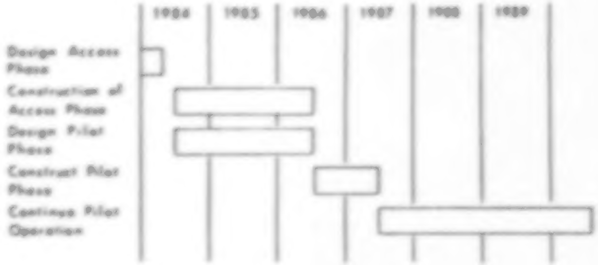


FIGURE 7

Close view of the Bit Cutter assembly. The bit has an overall diameter of 4.0m..

FIGURE 8

PROJECT SCHEDULE



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Underground Test Facility: Shaft and Tunnel Laboratory for Horizontal Well Technology

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SPE Members

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ABSTRACT

The Alberta Oil Sands Technology and Research Authority has initiated an extensive, long term program to evaluate horizontal well recovery processes in a shaft and tunnel complex in the Athabasca tar sands, 35 miles NW of Fort McMurray, Alberta.

The 213 m twin shafts, the initial pit bottom, tunnel development and the surface mine support equipment have been contracted. Shaft sinking started February 1985. Shaft No. 1 took 55 days to drill; No. 2 took 46 days. The access facilities are scheduled to be operational March 1986. Mine extension and pilot startup will be completed by mid '87, after which horizontal well drilling/completion technology and a variety of recovery strategies will be evaluated.

The commercial economics of the shaft and tunnel concept for bitumen recovery from the Athabasca tar sands will also be firmed up during this period. Initial feasibility studies were positive for this reservoir with 15 km of tunnel and 356 horizontal wells over the project life. Preliminary designs for well completion and process service facilities have been based on a steam recovery process. Ultimate production capacity is intended to be 1,600 m^3/day or 10,000 BPD.

HORIZONTAL RECOVERY PROCESSES

Theory and experience teaches that mobility ratios dominate volumetric sweep efficiency of a reservoir. The bitumens in the Alberta tar sands are so viscous that, if this experience holds for these reservoirs, heating to several hundred degrees would produce little improvement in overall volumetric recovery efficiency. Yet two of the current in situ tarsands projects that are expanding to commercial levels - Shell's Peace River project[1] and Esso's Cold Lake project[2] - are reporting recoveries in excess of 20%, and in the case of the Shell project, estimates of volumetric sweep efficiency indicate +50% possible. Clearly the inconsistency between theory and practice lies not with the reported performance of the field projects but with the theory. Gravity drainage is one factor that plays a considerable role.

At Shell's Peace River pilot a pressure cycling strategy is used. Steam is injected into a thin transition zone at the base of the reservoir. The steam rises and heats the bitumen which drains downward toward this higher permeability, water saturated zone. The hot oil is produced during the drawdown cycle. The excellent areal conformance of the steam through this bottom water zone combined with the improved vertical conformance caused by the downward movement of the mobilized bitumen appears to be the rational for the excellent recoveries already obtained after only several cycles of pilot operation.

With Esso's Cold Lake pilot, vertical fractures are created to achieve the requisite injectivity of steam for their steam stimulation operations. The lack of native injectivity confines the steam to the near-fracture region. Efficient flowback of the confined steam appears to be a dominant driving force for producing the heated bitumen. Gravity also plays a part. The heated bitumen can drain downward in the region of the fracture, allowing for further extension of the steam heated zone away from the fracture plane. The high initial oil saturation in this part of the Cold Lake reservoir combined with excellent vertical continuity maximizes the gravity head that governs the downward flow rate of bitumen. By analogy, what has been accomplished is akin to cracking a giant ice cube and injecting steam into the middle to melt the ice from the face of the crack. As with the Shell case, significant horizontal displacement of the bitumen is required to produce this fluid at a well which is acting in effect as a point sink for flow. In-house computer simulation suggests that this is the rate controlling step in the fluid production process.

In both Shell's and Esso's case, steam confinement appears to be critical to success. The horizontal, lower zone scheme used by Shell appears to give high ultimate vertical sweep. A vertical fracture tends to exacerbate gravity override of the steam with the result that areal conformance of the steam is less than that achieved if a zone having large areal extent and good injectivity characteristics was available.

These observations which motivate us to look toward lower zone horizontal based recovery processes tend to be born out in our analysis of other steam recovery pilots in Alberta. Oil productivity from forty steam pilots was examined. Oil/steam ratios were plotted against a number of parameters including reservoir thickness, presence of mobile water zones, temperature, net/gross pay thickness, fracture type, reservoir depth, porosity, original oil saturation, well spacing, oil gravity and absolute permeability of the reservoir.

Figure 1 shows that very few pilots in reservoirs thinner than 20 m will produce oil at high OSR's. Thicker reservoirs provide two advantages: less heat loss and improved gravity head. The thin reservoirs which did generate high OSR's were very homogeneous reservoirs that allowed steam to penetrate effectively.

In the Athabasca tar sands any pilot with a mobile water zone experienced poor oil recovery. Comparable but otherwise confined water zones at Cold Lake had significantly better recoveries. This suggests an axiom - it is not just water zones but unconfined water zones that deleteriously affect steam performance. Communication with mobile aquifers must be avoided thereby inhibiting the use of fractures in those reservoirs where penetration with active water zones is a real possibility.

Other things show up from these pilot analyses: a) vertical fractures in contained reservoirs are effective but not necessarily the optimum strategy since significant steam override occurs with vertical fractures; b) insufficient data are available to quantify the benefits of horizontal fractures; and c) the absence of vertical restrictions improves performance.

The field data and other theoretical work supports the view that gravity drainage is an important process mechanism for bitumen. Consequently for the Alberta tar sands, lower zone horizontal recovery processes should improve overall recovery and give higher OSR's.

Two horizontal based approaches to achieve these goals are: a) a horizontal fracture which acts as a "planar sink" for heat transfer and bitumen recovery; and b) horizontal wells acting as line sources for steam injection and line sinks for fluid recovery. Horizontal fractures are an option in shallow reservoirs less than 250 m deep. Horizontal wells would be an alternative in reservoirs deeper than 250 m where sustained lower zone horizontal fractures are not assured or for unique reservoir conditions, for example, where low injection rates are required to compensate for lack of steam confinement.

The idea of horizontal wells is not a new one but one which has made significant headway only over the last decade. In that time, numerous papers have reported the successful drilling of horizontal wells from surface locations.

Table 1 shows the number and location of some successfully drilled horizontal wells around the world. The Petroleum Institute of France and Elf-Acquitaine[8] successfully drilled and completed a horizontal well at a total vertical depth of about 3700 m with a horizontal length of about 400 m. Esso[10] reported the completion of two horizontal well pilots at Cold Lake, Alberta. The longest well had a total measured length of 1773 metres and a true horizontal section of 1016 m.

Another approach to drilling these wells in certain circumstances is from underground tunnels[14]. Mining access operations have been employed in the Romanian petroleum industry since 1925.[20] Shaft and tunnel production facilities are used in the Yarega and Balakhany oil fields[6,7] in the USSR. Today the Yarega oil field is in full scale commercial operation as a result of this development emphasis.

The Malta pilot in Ohio[13] has operated successfully since 1982 with the 46 m deep shaft and tunnel system which consists of 117 short horizontal wells. Hopco of California has also operated a similar shaft and tunnel system with 8 horizontal wells[11].

Obviously the technology is not new, both drilling from surface and the shaft and tunnel concepts have been explored widely. Advances have been made with respect to drilling technology (Table 2) but there still remains considerable development for increased commercialization. A number of these needs are listed in Table 3. Many of these can be effectively explored from a shaft and tunnel complex, particularly the mechanistic aspects of horizontal wells including recovery strategies, effective lengths and completion requirements. The commercial viability of a shaft and tunnel for Athabasca tar sands (there is yet no proven surface technology other than surface mining) can also be explored. Of particular concern for the first shaft and tunnel is the ability to gain access to the formation and the stability both during construction and after thermal stimulation. To encourage the development by assuming capital risk for this phase of operation is AOSTRA's rational for the AOSTRA sponsored "Underground Test Facility" or UTF.

UTF PROJECT - OVERVIEW

The pilot site is located on about 9 ha of Crown land set aside for this project some 60 kilometers northwest of Fort McMurray, Alberta, Canada. (Figure 2)

A total of 31 delineation wells have been either logged or cored at the UTF site to establish reserves in place and reservoir continuity within the McMurray formation. Table 5 depicts the average reservoir characteristics.

The geology to the target depth can be divided into 3 sections, each providing different drilling and hole conditions for shaft sinking:

i) The Clearwater and Grand Rapids Formations above the tar sands deposit consist of approximately 130 meters of interbedded claystones, siltstones and sandstones of the Cretaceous age underlying a thin veneer of unconsolidated glaciolacustrine silty sand and clay till.

The engineering properties of this overburden section vary with lithology, degree of induration and type of cementing agent within the individual layers. Generally they can be classified as weak rocks. Site investigations indicate the potential of flowing water and sand close to the bedrock surfaces. Most of the overburden materials tended to be unstable when exposed to water wetting. Core samples from even the harder formations showed a tendency to break down into unbonded fines if placed in water for a short period of time.

ii) The reservoir section is in the McMurray Formation which is about 30 meters thick at the UTF site. It consists mainly of weakly cemented quartzitic sandstone saturated with bitumen and water. Undisturbed it is a relatively hard, abrasive material which tends to wear drilling tools quickly. Once disturbed by drilling, it becomes a loose mass of unbonded sand particles in a bitumen matrix.

iii) The sub reservoir section in the Waterways Formation beneath the McMurray Formation consists of beds of greenish grey argillaceous and clastic limestones. Because of the relatively strong nature of this rock underlying the oil bearing strata, it is considered a favourable location for the underground tunnels.

A schematic drawing of the Underground Test Facility is shown in Figure 3.

The surface plant for the mine consists of field personnel office, maintenance workshops, electrical sub station, compressors and stand by diesel powered generator, warehouses, water storage and fuel storage.

Additional facilities required for oil recovery operations include water treatment, steam generation, laboratory, separators, storage tanks, communication facilities, fresh water supply and produced water disposal systems.

THE SHAFTS

Two main shafts have been sunk through the McMurray formation to the underlying Devonian limestone at a depth of about 213 meters using the blind boring method. One of the shafts is for production and will be equipped with a headframe and hoist. The other will be used for service lines, ventilation and emergency egress.

Shaft sinking through the weak, semi-indurated sedimentary rock overburden and the potentially unstable tar sands characteristic of the region have been unsuccessful prior to those reported here. Because of the formation properties the selected shaft sinking method must either preconsolidate the matrix or provide support during or shortly after excavation. Large-diameter blind shaft drilling was the method chosen as it offers some particular advantages over conventional shaft sinking techniques. Four of these considered important were the ability to control ground water and unstable formation through a suitable drilling fluid; speed and predictability of the construction period; prevention of gas dissolution from the oil sands thus preserving its in situ strength; and safety since men are not required to enter the shaft until it is completely lined.

The first shaft was spudded February 4, 1985. Actual drilling time through the overburden was 497 hours for an average penetration rate of 0.24 m/hr. Through the tar sand section the penetration rate was 0.31 m/hr. for a total drilling time of 102.5 hrs. The rate of penetration dropped within the limestone basement to 0.11 m/hr. During this period, the bit was pulled, inspected and found to be in good condition, although the chalkie limestone cuttings tended to be packed tightly between the cutter teeth.

Total depth for the first shaft was reached March 30, 1985, 54 3/4 days after spudding. The second shaft was completed June 29. Only 46 days were required for drilling.

The success in drilling these shafts indicate that the relatively low degree of disturbance incurred by this method and the polymer drilling fluid used were adequate to maintain the stability of the shaft walls within this critically weak formation.

A 3.05 m ID stiffened, thin walled steel liner was run into the hole after drilling was completed. Three principal loading conditions had to be considered in the overall design: liner weight, hydrostatic/lithostatic pressure and out of roundness. A summary of the liner design is shown in Table 4. Details of the geotechnical design parameters which must be considered for both initial conditions and changing conditions caused by the thermal recovery operations are detailed elsewhere[16].

The liner was "floated" into the hole in 13.5 m sections weighing 9 tonnes. The sections were welded together as they were lowered into the hole. Each joint required 6 hours with a 6 man welding crew. A total of 13 days was required to install the liner. That the liner hung free and could be rotated by hand until the last joint was added attested to the stability of the hole.

The liner was cemented in place using 1164 T of cement, placed in 6 stages over a period of 6 days via grout tubes welded to the outside of the liner assembly.

THE TUNNELS

A pit bottom service tunnel complex is part of the access facilities and includes the workshop, substation, and refuge chamber to service the mine. Total tunnelling from No. 1 shaft for this stage of development is 225 m and 215 m from shaft No. 2 plus cross cuts to connect the two tunnels.

These tunnels will be drilled with jack legs in a predesigned pattern, loaded with selected explosives and blasted. This should give smooth walls, roofs and blasted rock of optimum size. This relatively simple and unsophisticated method of excavation is chosen because the short runs and numerous changes in direction and dimensions are not condusive to mechanical means of excavation. The rock is expected to be competent and the amount of support will be kept to a minimum.

Before break-out from the shafts the adjacent strata has to be tested for the presence of gas and water. This will be done by drilling the rock to a depth of 2 meters from the inside of the shaft through pre-installed ports in the steel liner. If there are significant gas or water flows, remedial measures such as grouting and methane drainage will be undertaken.

From the pit bottom complex, a system of production tunnels will be driven through the limestone to provide access for drilling horizontal wells up into the McMurray formation. One tunnel, 20 metres below the base of the oil sand, will be used for the access and main ventilation purposes. The other, 8 m below the base of the oil sands, will be used for drilling the wells. It is expected that these extended tunnels will be constructed with conventional rubber wheeled road heading equipment.

HORIZONTAL WELL DRILLING

While most of the technology and equipment to drill underground wells is available, considerable innovation and modification will be required to adapt the technology for drilling upslope/horizontal wells. The areas that require new technology and equipment are: the drill itself; pressure control equipment; methods of running and cementing casing; and a non-magnetic direction surveying system that is fast and reliable.

To place completed wells near the base of the oil sands from underground tunnels demands not only a special drill, but a drilling system to go with it. The anticipated size of the drilling machine will require it to be disassembled for lowering into the mine. An equipment assembly station with overhead crane will be installed at the bottom of the No. 2 shaft for re-assembly of the equipment.

Once downhole, the drill must be capable of drilling from mine tunnels, and be able to place wells in a closely spaced configuration. Among the patterns that may be required, perhaps the most exacting is the proposal to drill dual horizontal wells, one placed several meters above the other; the upper to be used as a steam injector, the lower one for production.

Drilling from a tunnel in the limestone requires that holes be drilled on the upslope, through the limestone and deviated to the horizontal several meters above the base of the tar sands after which drilling would continue horizontally for the remaining length of the well (Figure 4). To do this the drill should be capable of handling drilling tools longer than the width of the tunnels. It is proposed that these long-tools be placed in a "mouse-hole" drilled in the opposite side of the tunnel. The tools could then be inserted into the hole by the drill. The drill must also be equipped with a pipe handling device to manipulate the drill tools, drill pipe and casing within the confines of the mine tunnels.

No underground drills are available that meet all the requirements for such a specialized duty, consequently it is to be designed and developed by drill manufacturers working closely with drilling and mining engineering personnel.

The drilling programme will require that a conductor hole be drilled for several meters and conductor pipe be cemented in place. A control head will be attached to the conductor pipe to control any flow of fluid that may be encountered while drilling the surface hole. Next the surface hole will be drilled and surface casing cemented in place. After the control head is attached to the surface casing the main hole will be drilled.

Since underground drilling does not have the advantage of a hydrostatic head to contol pressures, the wellhead must also be designed to allow all drilling and completion operations to be done in a "packed-off" condition.

In order to maintain directional control of the hole while drilling, it will be necessary to run some type of steerable assembly. The most commonly used system in the oil and mining industry is a down hole mud motor and a bent sub assembly and a similar system is intended for this operation.

Two non-magnetic survey methods are being investigated for directional control. The first operates on a surface survey system that picks up signals sent out from a transmitter placed near the bit. The signals are computerized to give a continuous readout of the position of the bit.

The second method uses gyroscopic survey instruments. This type of instrumentation is currently being evaluated to determine, first, whether it can give the degree of accuracy needed to drill parallel holes and second whether it is of a sufficiently robust construction to avoid damage during use.

The two more conventional techniques for directional control will probably not be effective. Magnetic instruments will give good readings on the first well but once the hole is cased, this casing will interfere with the directional control on the second well. A mud pulse system relies on good hydraulic transmission which will probably not be the case with these up-slope horizontal wells.

The wells could be completed by installing a slotted liner in the hole or by running and cementing production casing as in conventional wells. The cementing and perforating of a production string would require that special tools and methods be developed. For example, swirl fins on the casing will aid even cement distribution as the casing is rotated during placement. Special centralizers need to be used to take the full weight of the casing. These centralizers must also be designed to slide into the hole.

The drilling limits regarding diameter and hole lengths will be explored in tests to be conducted at a surface outcrop site and later at the Underground Test Facility. By adapting present technology, 114 mm casing can be placed in 600 m holes. With experience longer, larger holes should be possible at acceptable costs.

RESERVOIR PERFORMANCE PREDICTION

Extensive thermal numerical reservoir simulations were performed to establish a prediction of performance from horizontal wells at the UTF site. The Computer Modeling Group's ISOM 3.0 model was used for the simulations[17]. ISCOM is a fully implicit, multi-component thermal simulator capable of simulating combustion or steam exploitation strategies.

A total of forty 2- and 3- dimensional simulations were carried out to investigate grid block size sensitivity, reservoir parameter sensitivities and different operating strategies. More complete details of the simulations are planned to be presented in a future paper.

The exploitation strategies studied included: cyclic steam with and without gas, steam drive, Chevron's HAS Drive[20], Steam Chamber[19] and BASIS. The last two are particularly interesting. The Steam Chamber process is a dual well process that uses the top horizontal well for steam injection at subfracture pressures and the bottom well for producing oil, formation water and condensed steam. The process involves counter-current gravity segregation of steam and mobile liquids. The steam rises, releases heat to the formation as it condenses and the hot lower viscosity bitumen and water drain to the bottom well. A steam-liquid interface is maintained between the injection and production wells to prevent excessive premature steam breakthrough to the production well.

The initial stage of operation involves a heating step to establish bitumen mobility in the reservoir surrounding the injector and producer. When established, the steam chamber grows rapidly towards the top of the reservoir. On reaching the cap, the chamber spreads laterally until it joins with the chambers from adjacent well pairs.

The BASIS ("Bitumen And Steam In Situ Separator") process is a single well process that utilizes counter-current steam-liquid flow but maintains the steam liquid interface at some point along the length of an inclined horizontal well (Figure 5). Steam is injected at the end of the inclined well either through tubing or through a vertical injector near the end of the inclined well. Liquid which flows into the well moves to the producing end of the inclined well. The process is controlled by maintaining a liquid level above the production end of the well.

Our numerical simulations indicate that per unit volume of reservoir the Steam Chamber process produced more oil and gave a higher oil steam ratio (OSR) over the BASIS process. Figures 6 and 7 illustrate the cumulative produced oil and cumulative OSR for the BASIS and Steam Chamber processes for 500 m long wells. At the end of 8 operating years the Steam Chamber process is estimated to produce 36,600 m^3 of oil at an OSR of 0.27 m^3/m^3 compared to BASIS with cumulative oil of 31,800 m^3 and an OSR of 0.23 m^3/m^3. These values translate to cumulative calendar day oil rates of 12.5 m^3/d and 10.9 m^3/d for Steam Chamber and BASIS, respectively.

The projected ultimate recovery of bitumen is 54% of the original bitumen in place after 8 years of operation on a Steam Chamber cell pair spacing of 26 m between pairs of horizontal wells. The high recovery of reserves in place is expected because of the extensive horizontal well contact with the reservoir on such close well spacing. Simulations indicated that larger well spacings would detrimentally affect both cumulative bitumen produced and OSR. Smaller spacings would be limited by economics.

The two-well Steam Chamber process is technically superior to other strategies we have simulated for the shallow McMurray depths. The influence of reservoir parameters on this process is a concern and the impact of some of these on oil recovery performance is summarized in Table 6. Increasing or reducing the relative permeability curve to water has minimal impact on cumulative bitumen produced or oil-steam ratio. The influence of water relative permeability is dominant within the steam chamber volume and hence would seem to have little effect on the bitumen recovery on the periphery of the chamber. On the other hand mobility of the bitumen is a factor. Decreasing the bitumen relative permeability curve by a factor of 2 decreased bitumen production by a factor of 2. Similarly increasing the volume of recoverable bitumen by 27% (by reducing residual oil saturation) increases cumulative bitumen recovered by 58% at 600 days. Decreasing the vertical permeability by a factor of four decreased bitumen recovery by a factor of 4 at 600 operating days.

The UTF site has extensive shale laminae in the upper intervals of the reservoir and this is accounted for in our numerical model by reducting k_v/k_h from 0.25 to k_v/k_h's equaling 0.10. Isothermal gas injectivity tests at the UTF site established a range of vertical to horizontal permeability ratios between 0.0 and 0.28. The simulation indicates that isolated occurrences of impermeable barriers will not detrimentally affect performance if average vertical permeability around these barriers provides a k_v/k_h greater than 0.25. A 10 meter wide barrier 5 meters above the steam injector in the steam chamber process would recover 94% of the bitumen that would be recoverd from the same reservoir without the barrier. Steam migrates to the base of the barrier and flows along the base until it has an opportunity to flow upward at the edge of the impermeable lense. A second steam chamber develops at the edge of the impermeable layer and thus does not substantially hinder performance.

Clearly a number of parameters need to be firmed up through field trails. In addition to the evaluation of the steam chamber process, the intent is to asses other steam recovery processes, identifying the cost/benefit of well length and diameter, evaluate different completion strategies, and demonstrate custom equipment performance.

ECONOMICS OF SHAFT/TUNNEL RECOVERY

Although used as a development facility for horizontal well recovery processes, the shaft/tunnel concept also has economic merit in some reservoir situations including the one at the present UTF site. This section summarizes the design, capital and operating costs to exploit the delineatd reserves.

After consideration of several combinations of tunnel layout and well length, a central spine tunnel configuration was selected as a reasonable and conservative scheme for the base case study. To provide for complete coverage of the reservoir, wells drilled from the outer drilling chambers are directed back across the tunnels. Such a pattern gives full coverage of reserves with the 500 m effective well length.

Since this is treated as a grass roots development, three shafts were specified for the mine access, and are sized to accommodate the eventual ventilation load imposed by the fully developed tunnel system.

The tunnel system is initiated by driving out four parallel tunnels from the shafts to the middle of the reserves area. From here the main system of tunnels is driven on a north/south line along the centreline of the reserves. The middle pair of tunnels in the system are used for services, transport and fresh air supply. The outside tunnels are the drilling and production chambers for the recovery operation and serve as the return air passages.

A total of 15.3 km of tunnel and 356 wells of 560 m length are put in place over a period of 14 years. This is accomplished by two mining spreads and two drilling spreads, well within the men and equipment handling capacity of the access system.

The envisaged operation of a commercial plant is similar to other in situ production schemes except that the distribution and production gathering operations are carried out underground. Steam is generated in conventional field boilers and distributed down the shaft and tunnel system to the individual injection wells. Production from each producer is controlled by density meter to prevent steam blowby. This system provides for efficient use of steam; reservoir pressure and steam injection rates are set in effect by the ability of the reservoir to produce. Production is gathered to underground satellites for well testing and pumping to surface.

Preliminary studies were run to check the economics at various rates of production from the delineated reserves. The cost of supply rose for operations below about 1200 m^3/d because of economies of scale and above about 2000 m^3/d because of reserve limitations on the larger plant. Nominal project sizing was set at 1600 m^3/d (10000 BPD).

Capital costs estimates for all aspects of the operation which are unique to this program were derived from quantity take-offs and unit pricing of labour, material and services. These facilities included shafts and tunnels, well drilling and completion, underground distribution and production gathering systems and mine services. Cost estimates for conventional facilities such as water treatment, steam generation, production treating and support facilities were derived from inhouse AOSTRA data for commercial facilities correlated to plant size.

The facilities and capital costs estimated for the base case development are listed in Table 7. These costs include the full program of mine and drilling development.

Operating costs for facilities unique to the Shaft/Tunnel approach and horizontal well processes were derived from planned operating and maintenance schedules, staffing plans and estimates of materials and services requirements. Operating costs for conventional facilities were derived from inhouse AOSTRA data correlated generally on a unit capacity basis.

Estimated operating costs for the base case operation in a typical operating year are listed in Table 8. All costs are in mid-1985 Canadian dollars.

Our supply price economic analysis indicates that at a 10% discount factor the process under this configuration will deliver bitumen at a supply price of $\$112.74/m^3$ exclusive of taxes and royalties. Table 9 shows the breakdown of cost components contributing to the final supply price. The advantage of presenting such a supply price is that it precludes the requirement for undertaking detailed sensitivity analyses for cost overruns or simple changes in facility design. For example, a doubling of the natural gas price would result in a doubling of the cost share for the fuel component without affecting the other elements contributing to the total supply price.

One point to note from this component analysis is that fuel for steam generation is the major cost of the project, accounting for almost 1/3 of the delivered cost of the bitumen. This implies that any process which provides even moderate fuel savings can have a substantial impact.

The second largest cost share is that associated with the overall mining activities including sinking the shafts, excavating the tunnels, and providing other subsurface equipment other than the gathering and distribution system. These underground facilities constitute approximately 20% of the total supply price.

The third largest component in the delivered price of bitumen is that associated with the drilling and operation of the underground wells. Drilling and workover costs contribute in excess of 15% of the final delivered supply price. It is to be noted that this drilling cost is premised on a per well cost of $184,000/year and that the workover cost is assumed to be $20,000/well/year. The analysis would suggest, for example, that rather than a dual well process, a comparable single well process such as BASIS could be developed, then the delivered cost of bitumen would fall by as much as 8% ($\$9/m^3$).

CONCLUSIONS

The concept of horizontal well technology for exploiting the bitumen reserves in Alberta offers tremendous potential but the high cost of trial and error evaluation of horizontal wells drilled from surface locations would inhibit many companies. On the other hand, a shaft and tunnel access to the deposit for subsequent horizontal well drilling offers considerable potential for exploring process technologies. Some of these include the identification of optimum completion and recovery strategies. At certain locations such as that choosen for the UTF project, a shaft and tunnel scheme also shows commercial promise to be confirmed during piloting operations.

ACKNOWLEDGEMENT

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TABLE 1
SOME REPORTED HORIZONTAL WELLS FOR OIL RECOVERY

PILOT/FIELD (DATE)	LOCATION	NO. OF WELLS	TOTAL VERTICAL	HORIZONTAL LENGTH (M)	REF.
Esso Horizontal Well Pilot ('79-84)	Cold Lake	2	519	1016	10
Texaco Athabasca Pilot ('81)	Steepbank Alberta	3	135	350	5
MAISP Petro-Canada	Mildred Lake Alberta	3	60	300	12
Lacq Oil Field LA 90 ('80)	S.W. France	1	670	100	9
Lacq Oil Field LA 91 ('80)	S.W. France	1	1367	514	3
Upper Lace Field ('82)	Rospo Mare	2	1498	662	19
Yarega Oil Field ('72-84)	Ukhta, USSR	Shaft and Tunnel System			7
Balakhany Field ('72-84)	Azerbaijan, USSR	Shaft and Tunnel System			6
North Tisdale Field ('77-84)	Casper Wyoming	Shaft and Tunnel System 13	70	75-520	4
Caster Lou Field ('83)	S.W. France	1	3665	389	8
Malta New Tech. Oil ('82-84)	Ohio	Shaft and Tunnel System 117	46	61	13
Hopco Cornell Heavy Oil ('82-84)	California	Shaft and Tunnel System 8	152	130-210	12
Petrobrass Fazenda Belem Field ('82-84)	Brasil	1	350	166	12

Table 2

WHAT HAS BEEN LEARNED ABOUT DRILLING HORIZONTAL WELLS

Logging procedures have been developed but require perfecting

Experience shows small deviation angles must be used (max 2 degrees/10 m)

Accurate efficient directional drilling techniques need to be developed

Drilling horizontal sections must be done with light weight pipe

Costs of horizontal wells fouund to be 3 to 6 times vertical wells

Core can be cut successfully

Pipesticking has presented some problems

Sand production has presented some problems in unconsolidated reservoirs

Some problems inserting liners

Table 3

FURTHER TECHNOLOGY NEEDS FOR HORIZONTAL WELL RECOVERY PROCESS

Reservoir Engineering:

- Oil Recovery Strategies
- Well Placement & Spacing
- Effective Well Length
- Impact of Geology eg. Barriers & Underlying Water

Production and Completion:

- Cost Reduction Strategies
- Completions in Unconsolidated Sands
- Pumping Methods
- Effective Fluid Injection

Table 4
3.05 METER LINER DESIGN

Depth (Meters) From	To	Design Pressure (KPa)	Wall Thickness (mm)	Stiffener Ring Size (mm x mm)	Ring Spacing (mm)
211.5	201.5	3,762	20	100 x 173	1,111
201.5	189.5	3,557	20	100 x 173	1,200
189.5	117.5	3,300	20	100 x 173	1,333
117.5	105.5	2,856	20	100 x 173	1,500
105.5	93.5	2,567	20	100 x 145	1,500
93.5	81.5	2,279	16	100 x 145	1,200
81.5	69.5	1,990	16	100 x 145	1,333
69.5	57.5	1,701	16	100 x 110	1,500
57.5	33.5	1,413	16	100 x 110	1,714
33.5	0	1,037	16	100 x 60	1,714

Table 5

AVERAGE RESERVOIR CHARACTERISTICS OF UTF SITE

Depth	150 m
Net Pay	20 m
Porosity	35%
Bitumen Saturation	81%
Water Saturation	19%
Horizontal Permeability	4D
Formation Pressure	450 kPa
Formation Temperature	11° C.
Bitumen Density	1030 kg/m^3

Table 6

TWO DIMENSIONAL STEAM CHAMBER SENSITIVITIES FOR RESERVOIR CHARACTERISTICS AT 600 OPERATING DAYS

Reservoir Sensitivity	Change From Base Case	Change in Cumulative Produced Bitumen From Base Case	Change in Cumulative Oil Steam Ratio From Base Case
Decrease Residual Oil Saturation From 0.25 to 0.10	1.27	1.58	1.37
Double Water Relative Permeability Curve Values	2.0	1.01	0.96
Decrease Water Relative Permeability Curve Values By a Factor of 225	0.0044	0.72	0.94
Reduce Vertical Permeability From 4D To 1 Darcy	0.25	0.28	0.56
Decrease Bitumen Relative Permeability Curve By a Factor of 2	0.5	0.46	0.60
10 Meter Wide Impermeable Shale Barrier 5 Meters Above Steam Injector	–	0.94	0.93

Table 7
CAPITAL COST FOR SHAFT/TUNNEL DEVELOPMENT

(Mid 1985 CDN \$ x 10^6)

1.	Pre development		\$ 6.77
	Dam construction	\$ 1.53	
	Site Preparation and camp	\$ 2.70	
	Engineering	\$ 2.54	
2.	Mine development and drilling		\$126.99
	Shafts, hoists and pit bottom	\$ 23.37	
	Tunnels	\$ 32.31	
	Other mine costs	\$ 5.81	
	Drilling and completion of wells	\$ 65.50	
3.	Surface Process Plant and Facilities		\$ 35.19
	Water treatment and recycle	\$ 8.40	
	Steam generation	\$ 16.85	
	Process treating	\$ 5.22	
	Tankage and handling	\$ 1.66	
	Other	\$ 3.06	
4.	Offsites		\$ 20.76
	Subsurface distribution	\$ 3.20	
	Production testing	\$ 11.74	
	Control and Monitoring	\$ 2.00	
	Electrical supply and distribution	\$ 3.07	
	Water supply	\$ 0.75	
	TOTAL CAPITAL COSTS =		\$189.71

Table 8
OPERATING COSTS FOR 1600 m^3/d SHAFT/TUNNEL DEVELOPMENT

(mid 1985 CDN \$ x 10^6)

1.	Fuel Purchase	\$ 18.04 /yr
2.	Mine O&M	\$ 3.10 /yr
3.	Surface Plant O&M	\$ 6.69 /yr
4.	Well Workovers	\$ 1.92 /yr
	TOTAL OPERATING COSTS	\$ 29.75 /yr

Table 9

BASE CASE SUPPLY PRICE AND COST SHARES

	Supply Price (\$/m^3)	Cost Share
Operating Costs		
Surface Operating and Fluid Processing	12.87	11.4%
Mine Operating	9.70	8.6%
Fuel for Steam Generation	35.40	31.4%
Subtotal Operating:	57.97	51.4%
Capital Costs		
Mining - Shafts	7.64	6.8%
- Tunnels	8.94	7.9%
- Other Mining	5.82	5.2%
Wells - Drilling	14.36	12.7%
- Workovers	3.29	2.9%
Subsurface Piping and Test Equipment	3.14	2.8%
Surface Plant	11.58	10.3%
Subtotal Capital	54.77	48.6%
Total Supply Price	112.74	100.0%

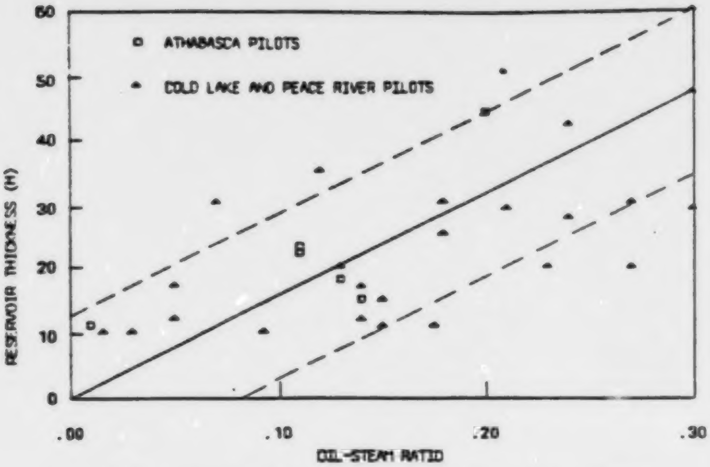


FIG 1 - EFFECT OF RESERVOIR THICKNESS ON OIL-STEAM RATIO

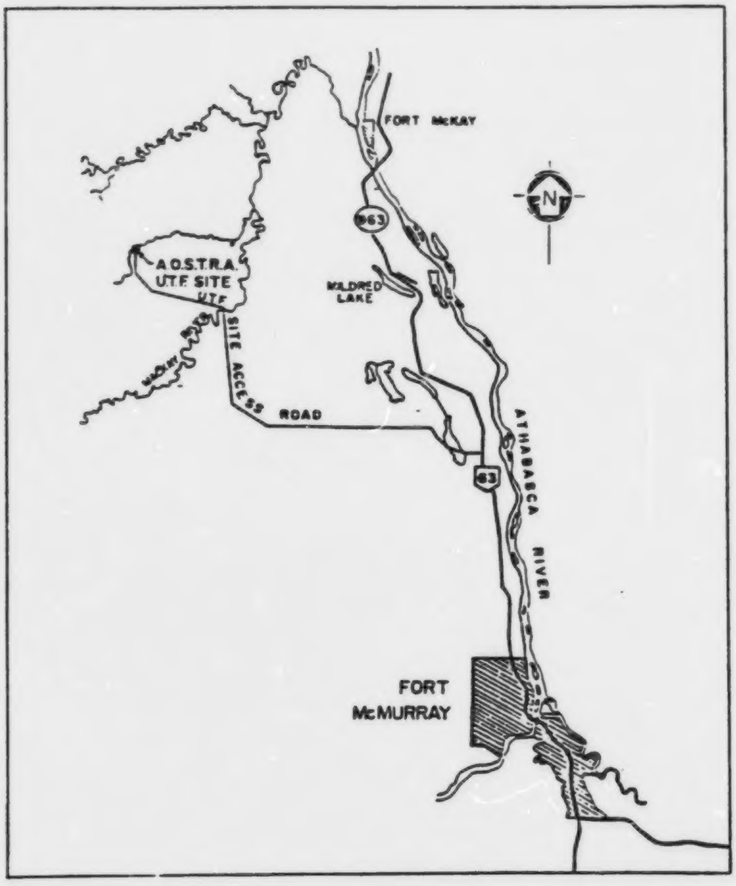


FIG 2 - LOCATION PLAN OF AOSTRA'S UNDERGROUND TEST FACILITY

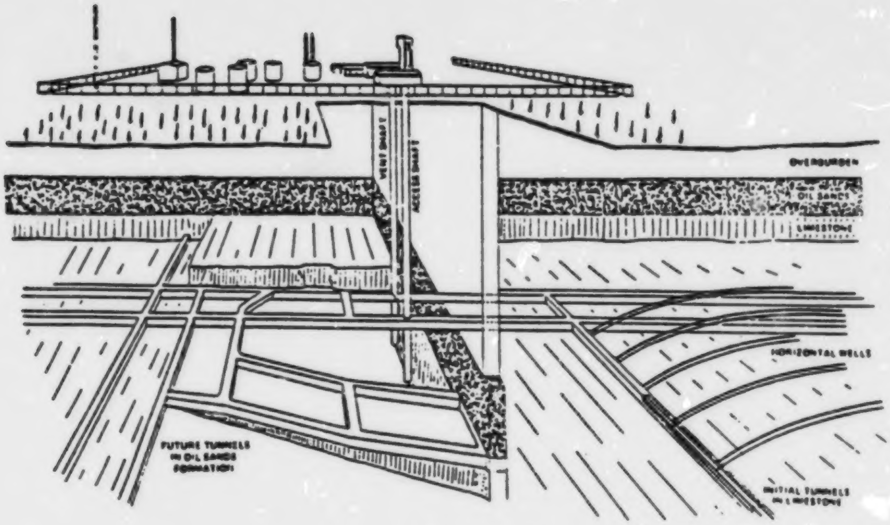
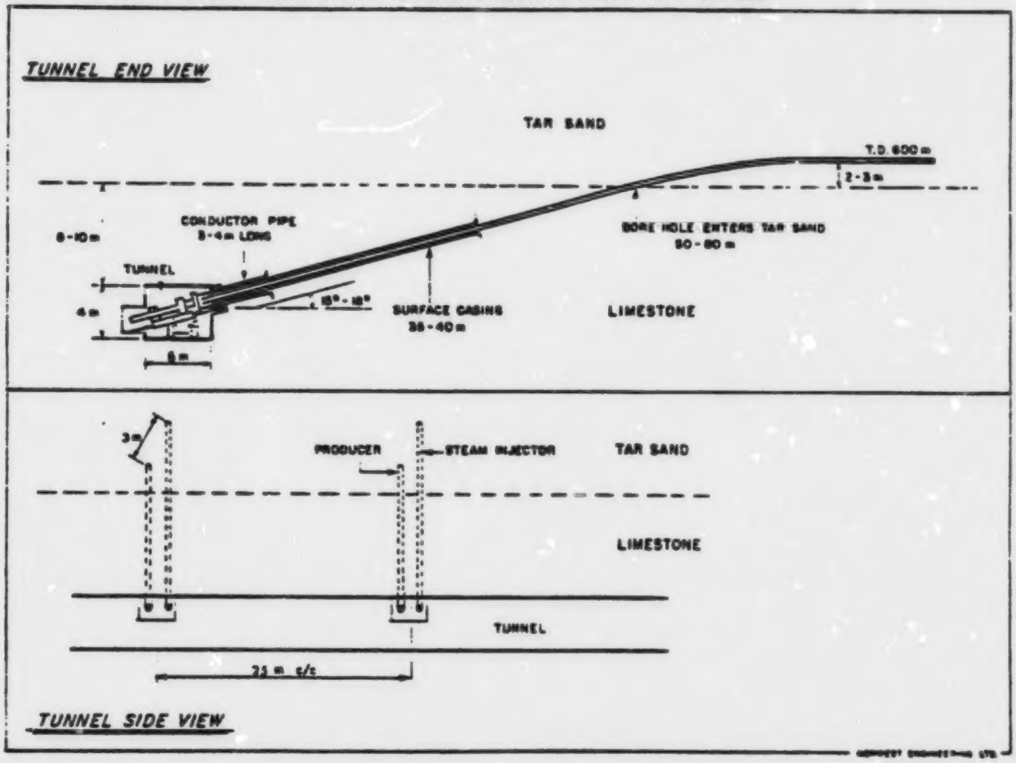


FIG. 3 - UNDERGROUND TEST FACILITY

FIG. 4 - CONCEPTUALIZED DRILLING SYSTEM TO DRILL HORIZONTAL WELLS FROM TUNNELS



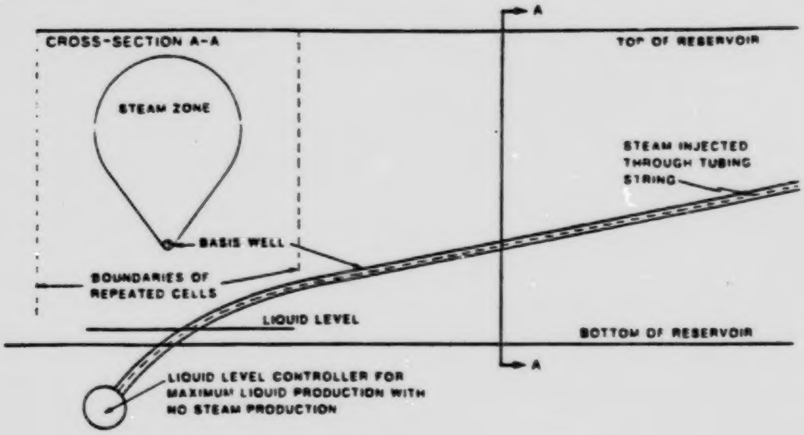

A
CROSS-SECTION A-A
TOP OF RESERVOIR
STEAM ZONE
STEAM INJECTED THROUGH TUBING STRING
BASIS WELL
BOUNDARIES OF REPEATED CELLS
LIQUID LEVEL
BOTTOM OF RESERVOIR
A
LIQUID LEVEL CONTROLLER FOR MAXIMUM LIQUID PRODUCTION WITH NO STEAM PRODUCTION

FIG 5 - BITUMEN AND STEAM IN-SITU SEPARATOR (BASIS) CONCEPT

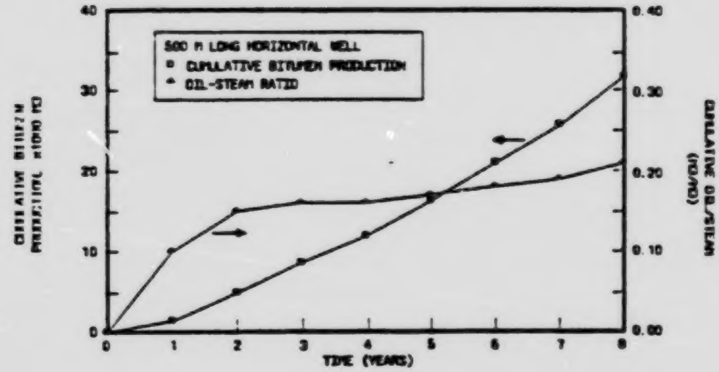


FIG 6 - UTF BASIS PROCESS CUMULATIVE OIL AND OIL-STEAM RATIO

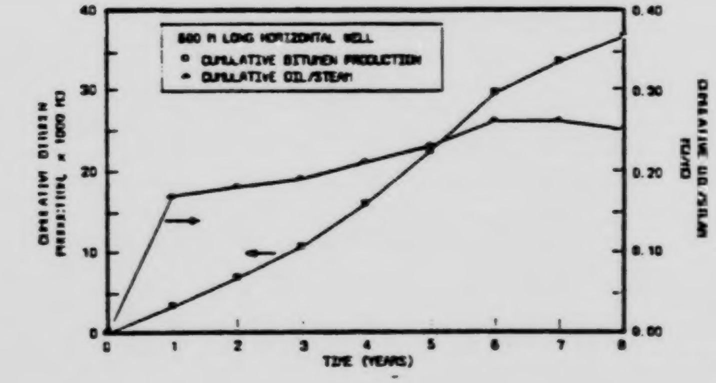


FIG 7 - UTF STEAM CHAMBER PROCESS CUMULATIVE OIL AND OIL-STEAM RATIO

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SESSION 1
PAPER 2

62

AOSTRA IN SITU RECOVERY PROGRAM

R.W. Luhning
Manager Thermal Operations
Alberta Oil Sands Technology & Research Authority

Advances in Petroleum Recovery and
Upgrading Technology
June 12 and 13, 1986
Calgary, Alberta

ERRATA

AOSTRA'S IN SITU RECOVERY PROGRAM

R.W. LUHNING
MANAGER, THERMAL OPERATIONS

SLIDE 2 AND 2A

FOR "PREP" READ "MULTISOAK"

FOR "THREE METRE THICK WATER SAND" READ "THREE METRE MOBILE WATER SAND".

FOR "THE PRODUCTION WELLS ARE THEN OPENED TO PRODUCE BLOWDOWN PRODUCTION" READ "THE PRODUCTION WELLS THEN PRODUCE BLOWDOWN PRODUCTION".

ADD "THE RESERVOIR IS THEN BLOWNDOWN AND THIS PROCESS IS REPEATED SEVERAL TIMES OVER THE LIFE OF THE PROJECT".

FOR "ABOUT 25% OF THE OIL IN PLACE" READ "33% OF THE OIL IN PLACE".

SLIDE 3C

FOR "COMBINES SUPERHEATED STEAM" READ "COMBINES SUPERHEATED/DRY STEAM".

SLIDE 4C

FOR "AT THE 100 METRE DEPTH" READ "AT THE 125 METRE DEPTH".

ADD "SOME OPERATIONAL PROBLEMS WERE ENCOUNTERED, INCLUDING SOLIDS INFLOW, UNEVEN COMMUNICATION, AND HIGH COST WORKOVERS. A SUCCESSFUL DRIVE, HOWEVER, WAS MAINTAINED BETWEEN TWO OF THE THREE WELLS, WHICH IN TURN PROVIDED SOME OPTIMISM THAT A FUTURE LARGE SCALE PATTERN USING HORIZONTAL WELLS MAY BE ECONOMIC. A DECISION WAS MADE TO CURTAIL PILOT OPERATIONS ON THE BASIS OF CURRENT ECONOMIC CONDITIONS AND THE FACT THAT THE PROJECT HAD APPROACHED THE END OF ITS USEFUL RESEARCH LIFE".

SLIDE 7A

FOR "THE MCLEAN PILOT HAS BEEN HAMPERED BY GEOLOGICAL PROBLEMS AND EXCESSIVE INTERWELL STEAM COMMUNICATION." READ "THE MCLEAN PILOT HAS BEEN HAMPERED BY GEOLOGICAL PROBLEMS AND OPERATIONAL PROBLEMS RELATED TO INTERWELL STEAM COMMUNICATION."

AOSTRA'S IN SITU RECOVERY PROGRAM

R.W. LUHNING
MANAGER THERMAL OPERATIONS

THIS PRESENTATION WILL DEAL WITH THE FIELD PILOT PROJECTS IN WHICH AOSTRA HAS BEEN INVOLVED OVER THE PAST 10 YEARS IN THE OIL SANDS, HEAVY OIL AND ENHANCED RECOVERY AREAS. THIS AMOUNTS TO A TOTAL OF 28 FIELD PILOTS. THIS REVIEW WILL HIGHLIGHT THE OBJECTIVES OF THE FIELD PILOTS, WHAT HAS BEEN LEARNED AND WHAT MAJOR TECHNICAL PROBLEMS REMAIN TO BE SOLVED.

SLIDE 1

A MAP OF ALBERTA SHOWING THE MAJOR DEPOSITS AND THE LOCATION OF THE AOSTRA FIELD PILOTS IS SHOWN IN THE FIRST SLIDE.

SLIDE 1A

THIS ACCOMPANYING SLIDE SHOWS THE PILOTS CONDUCTED IN THE MAJOR RESERVOIR AREAS. AS CAN BE SEEN, 3 OF THE FIELD PILOTS HAVE EXPANDED TO COMMERCIAL LIKE OPERATIONS, 18 PILOTS ARE CURRENTLY ACTIVE AND 10 FIELD OPERATIONS HAVE BEEN COMPLETED. THE TOTAL COST OF THE PILOTS, COMMITTED PLUS SPENT, IS APPROXIMATELY 700 MILLION DOLLARS. THE ACTIVITY IN EACH OF THE MAJOR DEPOSITS WILL NOW BE OVERVIEWED WITH THE PEACE RIVER OIL SANDS BEING THE FIRST CONSIDERED.

SLIDE 2 AND 2A

THESE NEXT TWO SLIDES SHOW THE AOSTRA PILOTS IN THE PEACE RIVER OIL SANDS WITH SOME DETAIL ON THE NATURE OF THE PILOTS. THE PRISP AND PREP PILOTS WERE OPERATED BY SHELL CANADA WITH AOSTRA, AMOCO AND SHELL EXPLORER AS PARTICIPANTS. THE PRISP PILOT WAS A PROTOTYPE SCALE PILOT OF SEVEN-SEVEN SPOT PATTERNS THAT USED A MODIFIED STEAM DRIVE TECHNIQUE FOR RECOVERY. THE PROCESS INVOLVES INJECTION OF STEAM INTO A THREE METRE THICK WATER SAND UNDERLYING THE 27 METRE THICK BULLHEAD PAY ZONE UNTIL THE RESERVOIR IS PRESSURIZED. THE PRODUCTION WELLS ARE THEN OPENED TO PRODUCE BLOWDOWN PRODUCTION. THE PROCESS IS VERY SUCCESSFUL WITH ABOUT 25% OF THE OIL IN PLACE RECOVERED TO DATE AND 55% PROJECTED AS THE ULTIMATE RECOVERY.

THE PREP PILOT IS FOUR WELLS USING CYCLIC STEAM STIMULATION PRODUCTION CONDUCTED TO DETERMINE IF STEAM CYCLE PRODUCTION COULD BE APPLIED BEFORE THE STEAM DRIVE PROCESS. STEAM WITH NATURAL GAS AS AN ADDITIVE IS UNDER TEST IN THE PILOT.

THE PILOTS HAVE LED TO A COMMERCIAL OPERATION AT PEACE RIVER WHICH WILL BE DESCRIBED IN MORE DETAIL IN A PAPER TOMORROW BY JOHN FLYNN.

SLIDE 3

THIS SLIDE SHOWS THE PILOTS IN WHICH AOSTRA HAS BEEN INVOLVED IN THE COLD LAKE AREA.

SLIDE 3A

A DESCRIPTION OF THE MARGUERITE LAKE PILOT OPERATED BY BP CANADA WITH AOSTRA, DOME AND PANCANADIAN IS GIVEN IN THE ACCOMPANYING SLIDE. THE MARGUERITE LAKE PILOT INITIALLY INVESTIGATED STEAM HUFF AND PUFF RECOVERY FROM THE 27 METRE THICK CLEARWATER HORIZON. AFTER COMPLETION OF THE STEAM HUFF AND PUFF PHASE, THE FOUR-FIVE SPOT PATTERNS WERE CONVERTED TO OXYGEN COMBUSTION USING A MODIFIED WET COMBUSTION DRIVE. THE OXYGEN OPERATIONS AT MARGUERITE LAKE ARE THE MOST ADVANCED IN THE WORLD AND THE PROCESS SHOWS STRONG POSSIBILITY OF BEING AN ECONOMIC METHOD TO RAISE THE ULTIMATE OIL RECOVERY BEYOND THAT POSSIBLE WITH STEAM HUFF AND PUFF RECOVERY.

THE WOLF LAKE COMMERCIAL OPERATION IS A RESULT OF THE PILOT ACTIVITY AND WILL BE DESCRIBED IN DETAIL TOMORROW BY TOM HARDING.

SLIDE 3B

THE NEXT SLIDE DESCRIBES THE B-UNIT PILOT WHICH IS OPERATED BY BP CANADA WITH AOSTRA AND PETRO-CANADA. THE PILOT WAS A SINGLE WELL PLUS TWO OBSERVATION WELLS IN THE LOWER GRAND RAPIDS FORMATION. THE PILOT INVESTIGATED STEAM HUFF AND PUFF RECOVERY COUPLED WITH A HORIZONTAL

FRACTURING TECHNIQUE. THE PILOT HAS COMPLETED FOUR CYCLES WITH THE RESULTS EXCEEDING THOSE PREDICTED BY RESERVOIR MODELLING STUDIES.

SLIDE 3C

BOW VALLEY IS THE OPERATOR OF THE ABC PILOT WITH AOSTRA AND COLD LAKE HEAVY OIL. THE PILOT IS AN ATTEMPT TO DEVELOP AN ECONOMIC RECOVERY PROCESS FOR A RELATIVELY THIN, 10 METRE THICK, SECTION OF THE CLEARWATER HORIZON WHICH HAS HIGH CLAY CONTENT. A PREVIOUS CONVENTIONAL STEAM HUFF AND PUFF OPERATION BY GULF AT THE LOCATION FAILED TO MEET ECONOMIC CRITERIA. AS SHOWN IN THE SLIDE, THE ABC PILOT COMBINES SUPERHEATED STEAM PLUS STEAM ADDITIVES WITH CYCLIC AND STEAM DRIVE OPERATIONS. THE ORIGINAL SEVEN SPOT PATTERN HAS GIVEN ENCOURAGING RESULTS TO DATE AND IT IS PLANNED TO DRILL A SECOND PATTERN THIS YEAR. THE TECHNOLOGY BEING DEVELOPED AT THE ABC PILOT WILL HELP TO OPEN MORE OF THE CLEARWATER HORIZON WHICH HAS SIMILAR THIN PAY TO ECONOMIC RECOVERY.

SLIDE 3D

SWARP IS THE ACRONYM USED TO DENOTE A JOINT SUNCOR, AOSTRA, CANADIAN WORLD WIDE ENERGY ENGINEERING AND FEASIBILITY STUDY ON THE USE OF STEAM ADDITIVES TO IMPROVE OIL RECOVERY AT THE SUNCOR FORT KENT COMMERCIAL OPERATION. THE STUDY BUILT ON THE PATENTED STEAM PLUS CARBON DIOXIDE AND NAPHTHA ADDITIVE PROCESS DEVELOPED BY AOSTRA AT THE ALBERTA RESEARCH COUNCIL. THE STUDY IS COMPLETE AND CONCLUDES THAT THE STEAM ADDITIVE PROCESS SHOWS PROMISE AT THE FORT KENT OPERATIONS PROVIDED THE ADDITIVES ARE APPLIED JUDICIOUSLY. THE STEAM ADDITIVE SYSTEM IS LESS PROMISING IN WELLS WITH NATURALLY HIGH GAS-OIL RATIOS.

SLIDE 4

AOSTRA HAS BEEN INVOLVED IN A NUMBER OF PILOTS IN THE ATHABASCA OIL SANDS. THIS NEXT SLIDE LISTS THE OPERATIONS WHICH HAVE BEEN COMPLETED IN THE ATHABASCA.

SLIDE 4A

THIS SLIDE DESCRIBES THE NUMAC OPERATED SURMONT TEST WHICH HAD AOSTRA GULF AND AMOCO AS PARTICIPANTS. THIS WAS A SINGLE WELL OPERATION WHICH ATTEMPTED TO CREATE AND MAP HORIZONTAL FRACTURES IN THE MCMURRAY FORMATION AT A DEPTH OF ALMOST 500 METRES. AT THIS DEPTH THE NATURAL IN SITU STRESSES DICTATE A VERTICAL FRACTURE. A HORIZONAL FRACTURE IS PREFERRED FOR PURPOSES OF WELL LINKUP TO OPERATE A DRIVE PROCESS. THE FORMATION WAS FRACTURED AND CEMENT GROUT INJECTED TO MARK THE FRACTURE LOCATION. POST CORING WAS CONDUCTED TO MAP THE FRACTURE BY RECOVERY OF THE CEMENT GROUT.

SLIDE 4B

AMOCO WAS THE OPERATOR OF THE PROTOTYPE SCALE BLOCK I PROJECT WITH AOSTRA, SHELL, SUNCOR AND PETRO-CANADA. THE PILOT WAS DESIGNED AS A PRE-COMMERCIAL DEMONSTRATION OF THE AMOCO COFCAW WET COMBUSTION DRIVE PROCESS ON COMMERCIAL WELL SPACING. THE TEST FOLLOWED 15 YEARS OF PREVIOUS PILOTING AT THE LOCATION. THE PROCESS IS DEPENDENT ON CREATING AND MAINTAINING GOOD INTERWELL COMMUNICATION BY FRACTURING. UNFORTUNATELY ON COMMERCIAL SCALE SPACING IT WAS NOT POSSIBLE TO MAINTAIN EFFECTIVE DRIVE COMMUNICATION AND THE PROCESS FAILED TO PRODUCE BITUMEN AT RATES WHICH COULD BE TRANSLATED INTO AN ECONOMIC OPERATION IN THE ATHABASCA.

SLICE 4C

TEXACO CANADA CONDUCTED STEAM RECOVERY OPERATIONS IN THREE HORIZONTAL WELLS AT FORT MCMURRAY. AOSTRA HAS ACCESS TO THE PILOT RESULTS THROUGH A LICENSE ARRANGEMENT. THE PILOT DEMONSTRATED THAT HORIZONTAL WELLS COULD BE EFFECTIVELY PLACED AT THE 100 METRE DEPTH IN THE MCMURRAY FORMATION. THE PILOT PROVIDED VERY USEFUL INFORMATION ON THE OPERATIONS AND PRODUCTION OF HORIZONTAL WELLS IN THE MCMURRAY. SAND CONTROL PROBLEMS IN THE WELLS HAMPERED OPERATIONS AND EVENTUALLY LEAD TO THE CURTAILMENT OF PILOT OPERATIONS.

SLIDE 4D

THE PCEJ GROUP OF PETRO-CANADA, CITIES SERVICE, ESSO AND JAPAN CANADA OPERATED THE STONEY MOUNTAIN ELECTRICAL HEATING PILOT AS DESCRIBED IN THIS NEXT SLIDE. AOSTRA, THROUGH LICENSE ARRANGEMENTS, HAS ACCESS AND USE RIGHTS TO THE TECHNOLOGY. THE PILOT INVESTIGATED THE USE OF ELECTRICAL HEATING TO CREATE INTERWELL COMMUNICATIONS IN THE MCMURRAY AT A DEPTH OF ABOUT 500 METRES. STEAM DRIVE OPERATIONS WERE TO FOLLOW THE COMMUNICATIONS DEVELOPMENT PHASE. THE RESERVOIR WAS SUCCESSFULLY HEATED WITH THE ELECTRICAL HEATING TECHNIQUE WHICH WAS AN EXCELLENT TECHNICAL ACHIEVEMENT. UNFORTUNATELY THE TECHNOLOGY DID NOT TRANSLATE INTO AN ECONOMIC PROCESS AT THIS TIME.

SLIDE 4E

GULF CANADA AND AOSTRA CONDUCTED A FEASIBILITY STUDY TO COMPARE THE RECOVERY OF BITUMEN FROM THE MCMURRAY ON THE GULF SURMONT LEASE USING HORIZONTAL WELLS FROM THE SURFACE VERSUS HORIZONTAL WELLS DRILLED FROM A MINE TUNNEL UNDER THE OIL SANDS. THE STUDY CONCLUDED THAT RECOVERY OF BITUMEN USING HORIZONTAL WELLS WAS TECHNICALLY AND ECONOMICALLY FEASIBLE. THE USE OF A SHAFT AND TUNNEL ARRANGMENT FOR THE PLACEMENT OF THE HORIZONTAL WELLS WAS ECONOMICALLY SUPERIOR TO THE HORIZONTAL WELLS FROM THE SURFACE FOR COMMERCIAL APPLICATION. THE FEASIBILITY STUDY DID NOT DEVELOP INTO A PILOT BECAUSE OF DELAYS CAUSED BY THE GENERAL ECONOMIC CONDITIONS IN 1981 AND 1982 WHEN THE STUDY WAS COMPLETED.

SLIDE 5

THE CURRENTLY ACTIVE AOSTRA PILOTS IN THE ATHABASCA ARE SHOWN IN THIS NEXT SLIDE.

SLIDE 5A

THIS SLIDE SHOWS THE PLANNED TESTING FOR THE AMOCO OPERATED GLISP PILOT WITH PETRO-CANADA AND AOSTRA. FOLLOWING THE SHUT DOWN OF THE PREVIOUS BLOCK I PROJECT, THE USEFUL EQUIPMENT WAS MOVED TO A MORE GEOLOGICALLY ATTRACTIVE SITE FOR THE TESTING OF STEAM BASED RECOVERY. THE GLISP PILOT WILL BE A STEAM DRIVE PILOT AT ABOUT 190 METRES DEPTH AT A LOCATION WITH 68 METRES OF PAY. THE WELLS IN THE INVERTED FOUR SPOT PATTERN WILL BE LINKED BY HORIZONTAL FRACTURING FOLLOWED BY STEAM DRIVE WITH ADDITIVES. THE MAIN PATTERN OF THE PILOT IS SCHEDULED TO STARTUP IN SEPTEMBER OF THIS YEAR.

SLIDE 5B

THE CANTERRA-TENNECO-AOSTRA KEARL LAKE PILOT IS A PROTOTYPE SCALE PILOT INVOLVING TWO PATTERNS OF DIFFERENT CONFIGURATION. THE PILOT IS TESTING A MODIFIED STEAM DRIVE RECOVERY PROCESS AT A LOCATION WITH THE MCMURRAY AT A DEPTH OF 150 METRES. THE A PATTERN OF THE PILOT HAS BEEN IN OPERATION FOR ABOUT 4 YEARS AND IN 1985 PRODUCED OVER 21,000 CUBIC METRES OF BITUMEN. THE B PATTERN OF THE PILOT WAS STARTED UP IN MID 1985 TO DUPLICATE THE SUCCESSFUL RESULTS OF THE A PATTERN IN A DIFFERENT PATTERN WITH DIFFERENT WELL SPACING.

THE MODIFIED STEAM DRIVE PROCESS INVOLVES CREATING COMMUNICATIONS BETWEEN THE WELLS BY HYDRAULIC FRACTURING FOLLOWED BY A UNIQUE COMMUNICATIONS DEVELOPMENT SEQUENCE. THE RESULTS OF THE PILOT ARE ENCOURAGING AND BUILT ON THE HARD WON EXPERIENCES OF THE EARLY YEARS WITH THE PILOT.

SLIDE 5C

THE RESULTS OF THE AOSTRA/GULF SURMONT SHAFT AND TUNNEL FEASIBILITY STUDY LED AOSTRA TO DEVELOP THE UTF SHAFT AND TUNNEL PROJECT ON AOSTRA'S LEASE WEST OF THE SYNCRUDE SITE. AOSTRA IS THE OWNER AND OPERATOR OF THE PROJECT. TO DATE TWO SHAFTS TO THE MCMURRAY FORMATION AT 220 METRES DEPTH HAVE BEEN DRILLED AND ABOUT 350 METRES OF TUNNEL PLACED IN THE LIMESTONE UNDER THE FORMATION. THE TUNNELS WILL BE FURTHER EXTENDED TO A TOTAL LENGTH OF ABOUT A KILOMETRE TO ACCOMMODATE THE PHASE A STEAM RECOVERY OPERATIONS. IN PHASE A THREE HORIZONTAL WELL PAIRS CONSISTING OF A STEAM INJECTOR AND PRODUCER SEPARATED BY ABOUT 2 METRES WILL BE DRILLED FROM THE TUNNELS. STEAM WILL BE INJECTED ALONG THE 100 - 130 METRE LONG INJECTION WELLS WITH SIMULTANEOUS PRODUCTION FROM THE NEAR BY PRODUCTION WELLS. THE PROCESS BEING TESTED IS CALLED THE GRAVITY DRAINAGE STEAM CHAMBER PROCESS.

THE RECOVERY OPERATIONS WILL COMMENCE LATE THIS YEAR AND WILL CONTINUE FOR TWO YEARS. BASED ON PHASE A RESULTS THE PILOT WILL BE EXTENDED WITH ADDITIONAL TUNNELLING AND HORIZONTAL PRODUCTION WELLS.

SLIDE 6 AND 6A

AOSTRA WAS INVOLVED IN THE LATE STAGES OF STEAM AND COMBUSTION TESTING IN THE WABASCA OIL SANDS WITH GENERAL AMERICAN AS SHOWN IN THE NEXT SLIDES.

THE PILOT CONSISTED OF A WET COMBUSTION DRIVE PROCESS TESTED IN AN INVERTED 7-SPOT PATTERN. SINGLE WELL STEAM HUFF AND PUFF TESTS WERE ALSO TESTED IN THE 6 METRE THICK WABISKAW HORIZON AT 360 METRES DEPTH. THE STEAM HUFF AND PUFF WELLS GAVE VARYING BUT SOMEWHAT ENCOURAGING RESULTS.

THE COMBUSTION PILOT FAILED DUE TO POOR INTERWELL COMMUNICATION AND LOW PRODUCTION RESULTS. THE OIL VISCOSITY IN THE WABISKAW FORMATION VARIES SIGNIFICANTLY OVER RELATIVELY SHORT DISTANCES. THE OIL AT THE COMBUSTION PILOT SITE WAS 50,000 M.PA.S WHILE OIL AT OTHER NEARBY WELLS WAS AS LOW AS 3200 M.PA.S. IT WILL BE DIFFICULT TO ADVANCE RECOVERY TECHNOLOGY IN THE WABISKAW FORMATION UNTIL A GEOLOGIC UNDERSTANDING OF THE OIL VISCOSITY VARIATION IS GAINED.

SLIDE 7

THIS SLIDE SHOWS THE PILOTS IN WHICH AOSTRA HAS PARTICIPATED IN THE GROSMONT CARBONATE.

SLIDE 7A

THE BUFFALO CREEK/MCLEAN PILOTS OPERATED BY UNOCAL WITH AOSTRA AND MOBIL (EX CANADIAN SUPERIOR) ARE SHOWN IN THIS SLIDE. PILOTING HAS BEEN ACTIVE SINCE 1976 AND HAVE TESTED BOTH STEAM AND COMBUSTION PROCESSES. THERE WERE A SERIES OF SINGLE WELL AND DUAL WELL TESTS WHICH CULMINATED IN THE MCLEAN PILOT WHICH WAS DRILLED AS A FIVE SPOT IN 1982 AND EXPANDED TO A SECOND FIVE SPOT IN 1984. BECAUSE OF THE REMOTE PILOT LOCATION, THERE IS WINTER ROAD ACCESS ONLY, THE COST OF PILOTING IS HIGH AND DIFFICULT. THE SINGLE WELL CYCLIC STEAM STIMULATION OPERATIONS HAVE GIVEN SPECTACULAR OIL PRODUCTION RESULTS WITH OIL RATES AS HIGH AS 87 METRES PER DAY. THE MCLEAN PILOT HAS BEEN HAMPERED BY GEOLOGICAL PROBLEMS AND EXCESSIVE INTERWELL STEAM COMMUNICATIONS. THE PATTERN IS BEING METHODICALLY TESTED THIS YEAR TO IMPROVE THE UNDERSTANDING OF THE RELATION OF GEOLOGY AND PATTERN OPERATIONS IN THE GROSMONT CARBONATE. TWO NEW CYCLIC STEAM PRODUCTION WELLS WERE DRILLED THIS WINTER TO TEST PRODUCTION IN AN AREA OFF-SETTING THE MCLEAN PILOT AND TO TEST THE OPERATIONS OF COMMUNICATING WELLS.

SLIDE 7B

CHEVRON WITH AOSTRA AND CANADIAN OCCIDENTAL OPERATED A SINGLE WELL STEAM HUFF AND PUFF OPERATION AT ALGAR IN THE GROSMONT CARBONATE. THE CARBONATE AT THE ALGAR SITE IS ASSOCIATED WITH A GAS CAP. THIS RESERVOIR SITUATION IS COMMON TO MUCH OF THE GROSMONT CARBONATE DEPOSIT. THE PILOT PROVIDED INFORMATION ON THE DIFFICULTIES WHICH WILL BE ENCOUNTERED WITH ATTEMPTS TO RECOVER BITUMEN FROM THE GROSMONT CARBONATE WITH ASSOCIATED GAS CAP. THE RESULT IS IMPORTANT SINCE THE IMMEDIATE POTENTIAL OF RECOVERY FROM THE GROSMONT CARBONATE IS LIMITED TO THE AREAS, SUCH AS AT BUFFALO CREEK, WHICH DO NOT HAVE SIGNIFICANT GAS CAP.

SLIDE 8

AS SHOWN IN THE NEXT SLIDE AOSTRA IS INVOLVED IN SEVERAL HEAVY OIL RECOVERY PILOTS.

SLIDE 8A

THIS SLIDE OVERVIEWS THE SHOP PILOT AT SUFFIELD OPERATED BY ALBERTA ENERGY COMPANY WITH AOSTRA, WESTCOAST AND DOME. THE RESERVOIR SETTING IS HEAVY OIL AND IS A 20 METRE THICK GLAUCONITIC SANDSTONE AT 900 METRES DEPTH WITH A THICK UNDERLYING WATER ZONE. THE PILOT HAS BEEN TESTING WET FORWARD COMBUSTION IN THE INVERTED FIVE-SPOT PATTERN FOR FIVE YEARS. THE RESULTS OF THE PILOT HAVE BEEN SATISFACTORY AND THE PILOT OPERATIONS HAVE BEEN EXTENDED FOR ADDITIONAL OPERATIONS BEYOND THE ORIGINAL TERMINATION DATE FOR THE PILOT.

SLIDE 8B

THE COUNTESS B PILOT NEAR BROOKS OPERATED BY PANCANADIAN AND LL&E IS A COMBUSTION DRIVE RECOVERY OPERATION BEING CONDUCTED IN AN UPPER MANNVILLE MEDIUM GRAVITY POOL WHICH IS APPROACHING THE END OF WATERFLOOD RECOVERY. AOSTRA OPERATES THE SUPPORT RESEARCH PROGRAM ASOCIATED WITH THE PILOT. THE PILOT HAS SHOWN SOME INCREMENTAL OIL RECOVERY DUE TO THE COMBUSTION OPERATIONS ALTHOUGH THE AMOUNT OF INCREMENTAL PRODUCTION IS SOMEWHAT MASKED BY THE SURROUNDING ACTIVE WATERFLOOD. THE PILOT OPERATIONS ARE CONTINUING BASED ON THE ENCOURAGING RESULTS TO DATE.

SLIDE 8C

AT BODO IN MID-EASTERN ALBERTA, NORCEN WITH AOSTRA, TEXACO, MURPHY AND CANADIAN OCCIDENTAL ARE STARTING A STEAM STIMULATION AND DRIVE PROJECT OFFSETTING THE EXISTING FIREFLOOD RECOVERY OPERATION. THE STEAM PILOT IS JUST GETTING UNDERWAY WITH THE FIRST WELL OF THE NINE SPOT BEING STEAMED RECENTLY. THE FIRST WELL HAS GIVEN VERY GOOD RESULTS. THE STEAM PATTERN RESULTS WILL BE COMPARED TO THE FIREFLOOD RESULTS.

SLIDE 8D

PETRO-CANADA WITH AOSTRA OPERATED THE KNOP PROJECT IN THE SPARKY FORMATION AT VIKING-KINSELLA NEAR WAINWRIGHT. THE PILOT OBJECTIVE WAS TO TEST AND COMPARE STEAM AND COMBUSTION AT THE SAME LOCATION IN EQUIVALENT PILOT PATTERNS. THE SANDS AT THE PILOT ARE 5 METRES THICK.

WHEN THE STEAM PATTERN WAS DRILLED A BARREN ZONE WAS FOUND IN THE MIDDLE OF THE PATTERN. THE STEAM PATTERN DID NOT PERFORM SATISFACTORILY AND WAS TERMINATED EARLY. THE COMBUSTION PILOT CONTINUED WITH INFILL DRILLING TO ADDRESS POOR CONFORMANCE EXPERIENCED IN THE COMBUSTION DRIVE PROCESS. THE COMBUSTION PATTERN CONFORMANCE PROBLEMS WERE NOT SOLVED BY INFILL DRILLING AND THE PILOT WAS TERMINATED AT THE END OF 1984.

SLIDE 9

IN 1981 AOSTRA'S MANDATE WAS WIDENED TO INCLUDE ENHANCED RECOVERY OPERATIONS. AOSTRA DEFINES ENHANCED RECOVERY OPERATIONS AS NON-THERMAL RECOVERY METHODS. THE PILOTS INVOLVING AOSTRA ARE SHOWN IN THIS SLIDE.

SLIDE 9A

THE JOFFRE PROJECT IS DESCRIBED IN THIS SLIDE. VIKOR RESOURCES WITH AOSTRA ARE CONDUCTING CANADA'S FIRST MISCIBLE CARBON DIOXIDE FLOOD PROJECT IN THE JOFFRE POOL NEAR RED DEER. THE 40° API JOFFRE POOL HAD PREVIOUSLY BEEN WATERFLOODED AND SUSPENDED. THE PILOT CONSISTS OF TWO FIVE SPOT PATTERNS WITH CARBON DIOXIDE SUPPLY COMING FROM THE NEAR-BY ALBERTA GAS ETHYLENE PLANT AND TRUCKED FROM EDMONTON. THE PILOT HAS BEEN IN OPERATION SINCE EARLY 1983 AND HAS GIVEN VERY ENCOURAGING RESULTS.

A COMMERCIAL EXPANSION IS UNDERWAY OFFSETTING THE ORIGINAL PILOT PLANT LOCATION.

SLIDE 9B

AT KITSCOTY IN THE LLOYDMINSTER AREA, HUSKY AND AOSTRA CONDUCTED CYCLIC WELL STIMULATION TESTS USING CARBON DIOXIDE. THE WELLS DID NOT RECEIVE ANY HEAT AND WERE ONLY STIMULATED WITH THE USE OF CARBON DIOXIDE. THE WELLS SHOWED SOME PRODUCTION RATE IMPROVEMENT WHEN STIMULATED WITH CARBON DIOXIDE, BUT THE PRODUCTION OF THE INJECTED GAS INCREASED SAND CONTROL PROBLEMS IN THE WELLS TESTED.

SLIDE 9C

AT CESSFORD NORTH OF BROOKS, AOSTRA IS PARTICIPATING WITH DOME AND SULPETRO IN THE TESTING OF CAUSTIC-POLYMER FLOOD ADDITION TO THE EXISTING WATERFLOOD. THE CAUSTIC PRE-CONDITIONING OF THE FLOOD WAS CONDUCTED IN 1984 WITH POLYMER INJECTION BEGINNING MID 1985. SEVERAL YEARS OF PROJECT OPERATIONS ARE ANTICIPATED.

SLIDE 10 AND 10A

WHAT PROGRESS HAS BEEN MADE OVER THE FIRST 10 YEARS BY AOSTRA? LET ME SUM UP THE MAJOR PROGRESS POINTS.

IN THE PEACE RIVER OIL SANDS, THE MODIFIED STEAM FLOOD TECHNOLOGY HAS BEEN DEVELOPED AND TRANSLATED INTO A COMMERCIAL OPERATION WHICH PROMISES TO YIELD VERY HIGH ULTIMATE RECOVERY FROM THE RESERVOIRS.

SLIDE 10B

IN COLD LAKE, THE MARGUERITE LAKE PILOT HAS LED TO A COMMERCIAL CYCLIC STEAM PROJECT AT WOLF LAKE. THE DEVELOPING OXYGEN COMBUSTION TECHNOLOGY PROMISES AN ECONOMIC METHOD TO IMPROVE THE ULTIMATE RESERVOIR RECOVERY BEYOND THAT POSSIBLE WITH STEAM HUFF AND PUFF.

TECHNOLOGY DEVELOPMENT IS UNDERWAY USING STEAM ADDITIVE PROCESSES TO EXTEND ECONOMIC RECOVERY TO THINNER CLEARWATER AREAS AND TO IMPROVE THE ULTIMATE RESERVOIR RECOVERY.

RECOVERY FORM A ZONE OTHER THAN THE CLEARWATER HAS BEEN TESTED AND THE LOWER GRAND RAPIDS APPEARS PROMISING.

SLIDE 10C

IN THE ATHABASCA, COMBUSTION DRIVE, ELECTRICAL HEATING, HORIZONTAL FRACTURING AND HORIZONTAL WELLS HAVE BEEN INVESTIGATED.

STEAM DRIVE PROCESSES AT MODERATE DEPTH, SUCH THAT HORIOZNTAL FRACTURING FOR COMMUNICATION DEVELOPMENT IS POSSIBLE, APPEAR VERY ATTRACTIVE AND ARE UNDER ACTIVE PILOT OPERATIONS.

THE SHAFT AND TUNNEL CONCEPT FOR THE PLACEMENT OF HORIZONTAL WELLS HAS AN ECONOMIC ADVANTAGE OVER SURFACE HORIZONTAL WELLS. AOSTRA HAS STARTED A MAJOR PILOT PROJECT TO DEMONSTRATE THE SHAFT AND TUNNEL RECOVERY TECHNOLOGY IN ATHABASCA.

SLIDE 10D

COMBUSTION AND STEAM WERE TESTED IN THE WABASCA OIL SANDS AREA. A BETTER GEOLOGICAL UNDERSTANDING WILL BE NECESSARY TO ADVANCE THE RECOVERY OPERATIONS.

SLIDE 10E

IN THE GROSMONT CARBONATE, COMBUSTION, CYCLIC STEAM AND STEAM DRIVE PROCESSES WERE TESTED. RECOVERY OPERATIONS IN DIFFERENT GROSMONT RESERVOIR SETTINGS WERE TESTED. WELL COMPLETION TECHNIQUES PRESENT DIFFICULTIES IN SECURING GOOD THERMAL WELLS AND A NUMBER OF DIFFERENT TECHNIQUES HAVE BEEN EVALUATED.

METHODS TO SUSTAIN THE HIGH PRODUCTIVITY POSSIBLE FROM THE GROSMONT CARBONATE RESERVOIRS NEED FURTHER DEVELOPMENT AND ARE UNDER INVESTIGATION.

SLIDE 10F

IN THE HEAVY OIL AREA, COMBUSTION DRIVE IN A RESERVOIR WITH UNDERLYING WATER HAS GIVEN ENCOURAGING RESULTS. COMBUSTION DRIVE APPLICATION AS A FOLLOWUP TO WATERFLOOD IS UNDER TEST AND PROVIDING ENCOURAGING RESULTS.

THE COMPARISON OF STEAM AND FIREFLOOD APPLICATIONS IN HEAVY OIL HAS BEEN ADDRESSED AND CONTINUES.

SLIDE 10G

IN THE AREA OF ENHANCED RECOVERY TECHNIQUES, AOSTRA'S EFFORTS HAVE LED TO A COMMERCIAL MISCIBLE CARBON DIOXIDE FLOOD PROJECT AT JOFFRE.

CAUSTIC-POLYMER FLOOD AS A MEANS OF IMPROVING WATERFLOOD OPERATIONS IS BEING TESTED.

SLIDE 11 AND 11A

THE PAST 10 YEARS HAVE LED TO VERY SIGNIFICANT ADVANCES IN THE IN SITU RECOVERY AREA. WHAT TYPES OF FIELD PROJECTS IS AOSTRA CONSIDERING FOR THE NEXT FIVE YEARS? THESE NEXT TWO SLIDES OVERVIEW THE NEW PROJECTS WHICH AOSTRA HAS TARGETED FOR THE COMING YEARS. THESE ARE NOT IN ORDER OF PRIORITY OR ANY PARTICULAR ORDER. BECAUSE OF FINANCIAL CONSTRAINTS, THE TIMING OF AOSTRA STARTUP PARTICIPATION IN THESE PROJECTS WILL NEED TO BE PHASED OVER SEVERAL YEARS.

THE FIRST ON THE SLIDE IS A DEEP ATHABASCA PILOT. DEEP ATHABASCA MEANS BELOW 400 TO 500 METRES. AOSTRA'S CURRENT PILOTS ARE AT SHALLOWER DEPTHS WHERE INTERWELL COMMUNICATIONS CAN BE DEVELOPED EASILY WITH FRACTURING. A LARGE PERCENTAGE OF THE ATHABASCA DEPOSIT IS DEEPLY BURIED AND NEW METHODS NEED TO BE DEVELOPED TO EXPLOIT THE DEEP RESERVES.

A STEAM PATTERN PILOT IN THE LOWER GRAND RAPIDS IS TARGETED TO BUILD ON THE EXCELLENT SINGLE WELL CYCLIC STIMULATION RESULTS ACHIEVED IN THE AREA TO DATE. A PATTERN OPERATION IS NECESSARY TO EVALUATE INTERFERENCE BETWEEN WELLS WHICH MAY CAUSE A CHANGE FROM THE GOOD PERFORMANCE ACHIEVED IN SINGLE WELL OPERATIONS. DEMONSTRATED PATTERN PERFORMANCE WOULD LEAD TO EARLY POTENTIAL COMMERCIAL OPERATIONS.

A COMBINATION STEAM/OXYGEN RECOVERY PROCESS FOR A HEAVY OIL RESERVOIR IS DESIRED.

AOSTRA HAS CONDUCTED ENGINEERING STUDIES ON THE USE OF HORIZONTAL WELLS FOR CONVENTIONAL PRODUCTION. THE HORIZONTAL WELL CAN PROVIDE BETTER DRAINAGE, HIGHER PRODUCTION RATES AND HIGHER ULTIMATE RECOVERY THAN VERTICAL WELLS. ECONOMICS INDICATE THAT THE HORIZONTAL WELL WOULD BE SUPERIOR TO THE EQUIVALENT NUMBER OF VERTICAL WELLS. A TEST OF A HORIZONTAL WELL FOR UNSTIMULATED CONVENTIONAL PRODUCTION IS DESIRED.

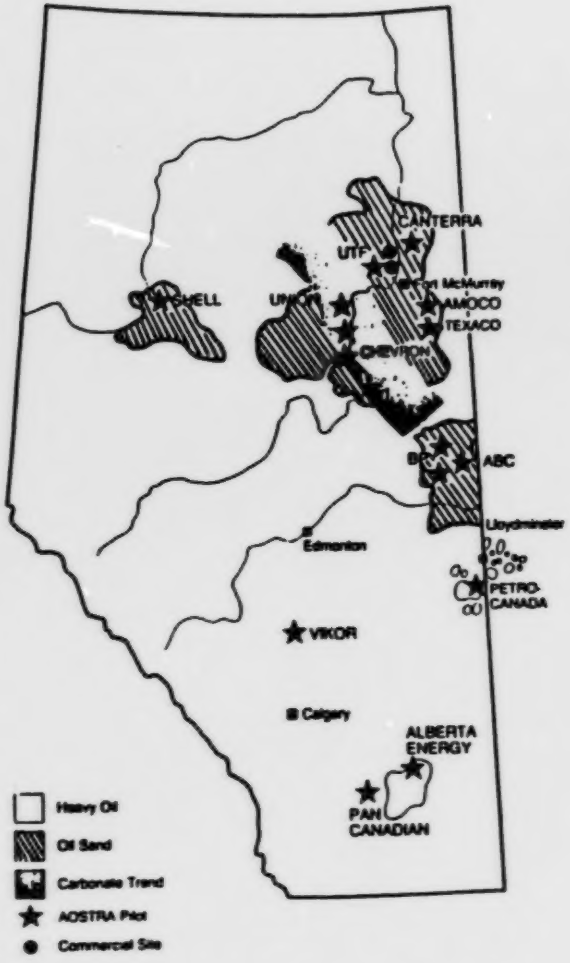
PEMBINA AND TURNER VALLEY REPRESENT LARGE CONVENTIONAL PRODUCTION RESERVOIRS WHICH ARE NEARING THE END OF THE WATERFLOOD PHASE. AOSTRA WOULD LIKE TO BEGIN AN ENHANCED RECOVERY PROJECT IN EACH OR BOTH OF THESE LARGE POOLS.

FINALLY AOSTRA IS ALWAYS OPEN TO OTHER GOOD PROPOSALS FOR FIELD OPERATIONS. THE TARGET OF THE FIELD OPERATIONS SHOULD BE SUCH THAT A DEMONSTRATION OF THE RECOVERY TECHNIQUES WILL LEAD TO EARLY COMMERCIALIZATION. ALSO THE TARGET RESERVOIR SHOULD BE LARGE SO THAT POSITIVE FIELD RESULTS MAY BE POTENTIALLY EXTENDED INTO MULTIPLE COMMERCIAL OPERATIONS.

THAT CONCLUDES MY PRESENTATION.

SLIDE 1

AOSTRA Field Pilot Projects



SLIDE 1A

AOSTRA FIELD PILOTS

- PILOTS -

	ACTIVE	COMPLETED	COMMERCIAL	TOTAL COST MM$
PEACE RIVER	2		1	178
COLD LAKE	4		1	70
ATHABASCA	4	5		245
WABASCA		2		25
CARBONATE	2	1		64
HEAVY OIL	3	1		88
ENHANCED RECOVERY	3	1	1	30

SLIDE 2

PEACE RIVER OIL SANDS

PILOTS	PATTERN
PRISP	7 - SEVEN SPOTS
PREP	4 - SINGLE WELLS

SLIDE 2A

PEACE RIVER OIL SANDS

PRISP

MODIFIED STEAM DRIVE

PREP

STEAM HUFF AND PUFF

- COMMERCIAL PROJECT CONSTRUCTED -

SLIDE 3

COLD LAKE OIL SANDS

PILOTS	PATTERN
MARGUERITE LAKE	4 - FIVE SPOTS
B-UNIT	SINGLE WELL
ABC PILOT	INVERTED SEVEN SPOT
SWARP	FORT KENT ADDITIVES STUDY

SLIDE 3A

MARGUERITE LAKE

- STEAM HUFF AND PUFF
- OXYGEN COMBUSTION

- WOLF LAKE COMMERCIAL PROJECT -

SLIDE 3B

B-UNIT

- CYCLIC STEAM WITH FRACTURING
- LOWER GRAND RAPIDS

- SINGLE WELL COMPLETED -

SLIDE 3C

ABC PILOT

- SUPERHEATED STEAM
- CYCLIC LEADING TO DRIVE
- ADDITIVES
    - CARBON DIOXIDE
    - CLAY SWELLING

- EXPANSION PLANNED THIS YEAR -

SLIDE 3D

SWARP

- STEAM ADDITIVES FOR FORT KENT
- RESEARCH AND FEASIBILITY

- STUDY COMPLETED -

SLIDE 4

ATHABASCA OIL SANDS

- COMPLETED PILOTS -

PILOTS	PATTERN
NUMAC SURMONT	SINGLE WELL
BLOCK I	9 - FIVE SPOTS
TEXACO	3 - HORIZONTAL WELLS
STONEY MOUNTAIN	INVERTED FIVE SPOT
GULF SURMONT	IN SITU MINE STUDY

SLIDE 4A

NUMAC SURMONT

- HORIZONTAL FRACTURING
- CEMENT GROUT
- POST CORING

- FRACTURE LOCATED -

SLIDE 4B

BLOCK I

- COFCAW
- PROTOTYPE SCALE
- COMMERCIAL SPACING

- UNABLE TO MAINTAIN COMMUNICATIONS -

SLIDE 4C

TEXACO

- HORIZONTAL WELLS
- STEAM DRIVE/STIMULATION

- SAND CONTROL PROBLEMS -

SLIDE 4D

STONEY MOUNTAIN

- ELECTRICAL RESISTANCE HEATING
- COMMUNICATIONS DEVELOPMENT
- STEAM DRIVE

- TECHNICAL ACHIEVEMENT -

SLIDE 4B

GULF SURMONT

- FEASIBILITY STUDY
- STEAM RECOVERY
- HORIZONTAL WELLS
    - FROM MINE
    - FROM SURFACE

- MINE ECONOMICALLY FEASIBLE -

SLIDE 5

ATHABASCA OIL SANDS

- CURRENT PILOTS -

PILOTS	PATTERN
GLISP	INVERTED FOUR SPOT
KEARL LAKE 'A'	SEVEN SPOT WITH SURROUNDING INJECTORS
KEARL LAKE 'B'	INVERTED NINE SPOT
[illegible]	SHAFT AND TUNNEL

SLIDE 5A

GLISP

- HORIZONTAL FRACTURING
- STEAM DRIVE
- STEAM ADDITIVES

- MAIN PATTERN STARTUP SEPTEMBER -

SLIDE 5B

KEARL LAKE 'A' AND 'B'

- MODIFIED STEAM DRIVE
- COMMUNICATIONS DEVELOPMENT

- 'B' PATTERN STARTED TO PROVE 'A' PATTERN -

SLIDE 5C

UTF

- SHAFT AND TUNNEL
- THREE HORIZONTAL WELL PAIRS
- STEAM CHAMBER PROCESS

- STARTUP LATE 1986 -

SLIDE 6A

JOLI FOU

- SINGLE WELL STEAM CYCLES
- WET COMBUSTION DRIVE
- WABISKAW SANDS

- VISCOSITY VARIATIONS IN WABISKAW -

SLIDE 6

WABASCA OIL SANDS

PILOTS	PATTERN
JOLI FOU	INVERTED SEVEN SPOT
JOLI FOU	SINGLE WELLS

SLIDE 7

GROSMONT CARBONATE

PILOTS	PATTERN
BUFFALO CREEK	10 SINGLE WELLS
MCLEAN	2 - FIVE SPOTS
ALGAR	SINGLE WELL

SLIDE 7A

BUFFALO CREEK/MCLEAN

- COMBUSTION DRIVE
- STEAM CYCLIC/DRIVE
- PATTERN STEAM DRIVE

- CYCLIC STEAM TESTING TWO NEW WELLS -

SLIDE 7B

ALGAR

- STEAM STIMULATION
- SINGLE WELL
- GAS CAP

- PROJECT COMPLETE -

SLIDE 8

HEAVY OIL THERMAL PILOTS

PILOTS	PATTERN
SHOP	INVERTED FIVE SPOT
COUNTESS B	INVERTED FIVE SPOT
BODO	INVERTED NINE SPOT
KHOP	
- STEAM	FIVE SPOT WITH SURROUNDING PRODUCERS
- COMBUSTION	FIVE SPOT WITH SURROUNDING PRODUCERS

SLIDE 8A

SHOP

- FORWARD WET COMBUSTION
- UNDERLYING WATER

- PILOT OPERATIONS EXTENDED

SLIDE 8B

COUNTESS B

- FORWARD WET COMBUSTION
- ACTIVE WATERFLOOD

- PILOT CONTINUES -

SLIDE 8C

BODO

- STEAM STIMULATION/DRIVE
- COMPARISON TO FIREFLOOD

- OPERATIONS BEGINNING -

SLIDE 8D

KRDP

- EQUIVALENT PATTERNS
- COMPARE
  - STEAM DRIVE
  - COMBUSTION DRIVE

- GEOLOGICAL PROBLEMS IN STEAM PATTERN -

- POOR CONFORMANCE IN COMBUSTION DRIVE -

SLIDE 9

ENHANCED RECOVERY - NON THERMAL

PILOTS	PATTERN
JOFFRE	2 - FIVE SPOTS
KITSCOTY	TWO SINGLE WELLS
CESSFORD	ADDITION TO EXISTING WATERFLOOD

SLIDE 9A

JOFFRE

- INFILL DRILLING
- WAG PROCESS
- CARBON DIOXIDE MISCIBLE

- COMMERCIAL EXPANSION -

SLIDE 9B

KITSCOTT

- CYCLIC STIMULATION
- CARBON DIOXIDE

- INCREASED SAND PROBLEMS -

SLIDE 9C

CESSFORD

- CAUSTIC-POLYMER FLOOD
- CAUSTIC PRE-CONDITIONING 1984
- POLYMER INJECTION MID-1985

- PROJECT CONTINUING -

SLIDE 10

PROGRESS

1976 - 1986

SLIDE 10A

PEACE RIVER PROGRESS

COMMERCIAL PROCESS WITH HIGH ULTIMATE RECOVERY

SLIDE 10B

COLD LAKE PROGRESS

- COMMERCIAL STEAM PROJECT (WOLF LAKE)
- OXYGEN COMBUSTION PROMISES ECONOMIC HIGHER ULTIMATE RECOVERY
- RECOVERY FROM THINNER ZONES WITH STEAM PLUS ADDITIVES
- RECOVERY FROM OTHER ZONES - LOWER GRAND RAPIDS

SLIDE 10C

ATHABASCA PROGRESS

- EVALUATED
    - COMBUSTION
    - ELECTRICAL HEATING
    - HORIZONTAL FRACTURING
    - HORIZONTAL WELLS
- STEAM DRIVE WITH COMMUNICATION DEVELOPMENT IS PROMISING
- SHAFT AND TUNNEL ACCESS IS UNDERWAY

SLIDE 10D

WABASCA PROGRESS

- EVALUTED
    - COMBUSTION
    - STEAM

SLIDE 10E

GROSMONT CARBONATE

- EVALUATED
  - COMBUSTION
  - CYCLIC STEAM
  - STEAM DRIVE
  - RESERVOIR SETTING
  - WELL COMPLETIONS
- METHODS TO SUSTAIN HIGH PRODUCTIVITY UNDER INVESTIGATION

SLIDE 10F

HEAVY OIL

- COMBUSTION DRIVE WITH UNDERLYING WATER IS PROMISING
- COMBUSTION FOLLOWING WATERFLOOD IS PROMISING
- COMBUSTION AND STEAM RECOVERY COMPARED

SLIDE 10G

ENHANCED RECOVERY

- COMMERCIAL CARBON DIOXIDE PROJECT AT JOFFRE
- CAUSTIC-POLYMER FLOOD TESTING IS UNDERWAY

SLIDE 11

WANTED

NEW PROJECTS

SLIDE 11A

WANTED NEW PROJECTS

- DEEP ATHABASCA PILOT
- STEAM PATTERN IN LOWER GRAND RAPIDS
- COMBINATION STEAM/OXYGEN COMBUSTION PILOT IN HEAVY OIL
- HORIZONTAL WELL FOR CONVENTIONAL RECOVERY
- ENHANCED RECOVERY IN PEMBINA OR TURNER VALLEY
- OTHER GOOD IDEAS
    - EARLY COMMERCIAL POTENTIAL
    - LARGE RESERVOIR TYPE

008752

Alberta OIL SANDS
INFORMATION CENTRE

63

H.H.A. HUYGEN, J.B. BLACK*

STEAMING THROUGH HORIZONTAL WELLS AND FRACTURES SCALED MODEL TESTS

1. SUMMARY

Steamflooding an immobile Athabasca tar sand was investigated in a scaled laboratory model. Horizontal and vertical wells and fractures provided injectivity. The objective was to identify favorable configurations for field testing in the Gulf/AOSTRA Surmont Project.

Scaling is discussed and equipment and procedure described. The tested geometries comprise linking between wells without fracturing, with fracturing, and steam circulation through a single, horizontal well with and without fractures.

Most configurations recovered more than half of the oil-in-place at oil-steam ratios of 0.2 or better. The single, horizontal well proved surprisingly effective; its geometric and interpretative simplicity recommends it for field testing.

RESUME

L'injection de vapeur dans un sable bitumineux immobile d'Athabasca a été étudiée à l'aide d'un modèle de laboratoire à l'échelle. L'injection fut assurée par puits horizontaux et verticaux; et par fractures. L'objectif était d'identifier les configurations favorables à un essai sur gisement pour le project Surmont de Gulf/AOSTRA.

La réduction à l'échelle, l'appareillage et la méthode d'essai sont descrites dans cette communication. Les géometries examinées comprennant liens entre puits, avec et sans fractures, et circulation de vapeur au travers d'un seul puits horizontal, avec et sans fractures.

La plupart des configurations ont recuperé plus de la moitiè du pétrole présent, avec des taux de pétrole-vapeur d'au moins 0,2. La technique d'un seul puits horizontal s'est avéreé très efficace; sa simplicité géométrique et d'interpretation est recommendée pour des essais sur gisement.

2. INTRODUCTION

The Alberta tar sands (designated oil sands in Canada) in the Western Canadian province of Alberta constitute a major alternative hydrocarbon resource base. Reserves are estimated at nearly 160 X 10^9 tons [1,2]. Only ten percent of these tar sands are considered shallow enough to be recovered economically by surface mining [1]. The remaining 90% are the target for various types of in-situ recovery techniques.

Thermal recovery techniques, including steaming and fireflooding, raise the temperature of the reservoir and its fluids several hundred degrees. As Figure 1 shows, this reduces the viscosity of a tar like Surmont by more than four orders of magnitude from 300,000 mm^2/s at reservoir temperature to less than 10 mm^2/s at steam temperature. This allows the initially immobile tar to flow quite easily. Furthermore, the injection of air (for combustion) or steam develops a pressure gradient which drives the mobilized tar to the production wells, thus augmenting gravity drainage drive.

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Steam, owing to its high sensible and latent heat content, is an effective carrier to deliver surface-generated heat to a tar sand. Steam drives exhibit good sweep and displacement efficiencies, even in heavy oil reservoirs and tar sands because of the favorable effects of steam condensation. They are operationally simple and straightforward and not apt to develop many problems.

Although sand permeability is high, steaming must overcome the obstacle of tar immobility which causes very low injectivity at the start of steam injection. The usual solution is to inject steam above fracturing pressure or into a high transmissivity channel such as a water zone. In the Surmont field, which is the subject of this study, water zones are absent or too high in the formation to give good vertical steam conformance. For this reason, horizontal wells have been proposed, both to achieve high steam injectivity and to obtain a flow channel linking injection and production wells. A further advantage is that a horizontal well can be placed low in the sand to delay gravity override of the steam zone. Moreover, its length is not limited to the height of the sand as vertical well length is.

Four years ago, Gulf Canada Resources, Inc. (GCRI) joined with the Alberta Oil Sands Technology and Research Authority (AOSTRA) in a project to utilize horizontal wells for steam injection. The objective of the first phase of the project was to develop a number of favorable configurations for field testing in GCRI's Surmont field during the second phase. To attain the objective, process mechanisms and performance of steamflooding were investigated in single and multiple, horizontal and vertical wells with and without fractures. All the work was experimental and performed in a three-dimensional, scaled, physical laboratory model, previously used at Gulf Research and Development Co. (GR&DC) for Wabasca studies [3]. Ten of the tests are presented here.

2.1 THE SURMONT FIELD

The Surmont field is located in the Canadian province of Alberta, near the eastern updip extent of the Athabasca deposit covering 48000 hectares. The target formation (McMurray-Wabiskaw) is about 30 meters thick at a depth of 300 meters. Estimated oil-in-place is 2500 million m^3. Specific gravity of the Surmont oil is 1.025 (API gravity is 6.5°). Measured kinematic viscosities indicate a value of 300,000 mm^2/s at the reservoir temperature of 21°C. First distillation overpoint at 336°C exceeds anticipated steam temperature. Asphaltene content is slightly over 14 percent. Indicated sand permeability in the vertical direction is of the order of 0.125 μm^2; the horizontal permeability is probably higher.

2.2 PAST WORK ON HORIZONTAL WELLS AND FRACTURES

Experimental work on horizontal wells has been reported in the literature by Butler, who analyzed [4] and tested [5] gravity drainage during steaming. Claims of laboratory work are made, but no results given, in an article [6] on proposed field testing in Kern River of a patented method [7] for cyclic steam stimulation from horizontal wells, drilled like spokes from a central mine shaft. It is unclear whether fractures are intended or not; these would greatly affect sweep efficiency and oil recovery. The earliest patent may be Ranney's [8] dating to 1944. Other pertinent patents are held by Butler [9] and by Butler et al [10]. The drilling of a horizontal well in Imperial's Cold Lake field has been reported by Bezaire [11]. Performance of vertical fractures from an inclined wellbore was analyzed by Strubhar [12]. Fracturing methods based on thermal alteration of formation stress states have been patented by Matthews [13] and Closmann [14] and analyzed for oil sands by Settari and Raisbeck [15].

2.3 PAST WORK IN SCALED, PHYSICAL MODELS

The use of three-dimensional, scaled models for laboratory studies of steaming at GR&DC dates back to the sixties [16].

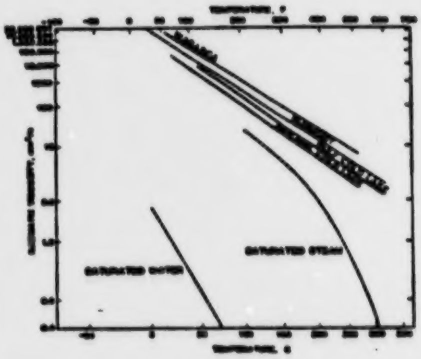

Fig. 1 - Viscosity vs. temperature

Pursley [17] (1974) reported steamfloods of Cold Lake oil; Bursell and Pittman [18] (1975) studied Kern River crude; Huygen [19] (1976) included Cold Lake crude in addition to lighter crudes; Ehrlich [20] (1977) tested barriers and additives with steamflooding the Grand Rapids "A" Wabasca formation; Prats [21] (1977) modeled pressure cycling the Peace River formation in a vacuum model that was later described by Stegemeier et al [22]; Huygen and Lowry [3] (1979) investigated pilot and fieldwide steamflooding through the bottom water zone of the Wabasca oil sand. The state of the art in physical and numerical modeling applicable to oil sands was surveyed by Farouq Ali and Redford [23] (1977); Singhal [24] (1979) has published an extensive and excellent survey of laboratory model work.

3. SCALING

For accurate physical modeling of steaming through horizontal wells, we must scale both heat flow (conduction and convection) and mass transport (including gravity drainage and phase changes). The oil used in the experiments is an Athabasca oil similar to Surmont oil. The sand has thermal properties similar to the reservoir rock. Steam temperatures and pressures approximate those in the field. Scaling of the various parameters conforms to Pujol and Boberg [25] and to Ehrlich [20].

The geometric scaling factor is fixed by the ratio of field-to-model formation thickness (200). For proper scaling, three independent groups should remain invariant from field to model: length ∙ flux, time/area, and permeability ∙ length. It follows that permeability, time, and rate are scaled as shown in Table I. Relative permeability and capillary forces are not scaled properly; the latter have been shown negligible by Pujol and Boberg [25]. From the Darcy flow law, it can be shown that the pressure gradient is invariant from field to model, provided fluid viscosity is the same which is the case. This implies that pressure differences in the model are small and therefore fluctuations should be carefully avoided.

4. EQUIPMENT

The 3-D, scaled model assembly consists of the steam generator, the pressure vessel containing the model formation, the production system, and the oil saturation system (Figure 2).

The 30 kilowatt Ebcor electric steam generator is capable of generating up to 45 kg/hr of dry steam at pressures up to 3 MPa. The boiler is pressure controlled. A steam/hot water separator prevents steam from being dumped down the lab drains. After separation, the steam is vented outside and the water flows down the drain. The separator is used mostly during generator warm-up and blow down.

The flanged, 3 MPa (315°C) pressure vessel contains in its bottom half a 54 cm X 54 cm X 15 cm high cavity, clad with 0.6 mm, 316 stainless steel. It is packed with sand to serve as the formation. The cavity is surrounded by insulating Sauereisen cement, which contains hundreds of 6.4 mm vertical steel rods to scale the over- and underburden thermal conductivity. After the sand is packed flush with the top of the Sauereisen, it is sealed with a

TABLE I: SURMONT MODEL SCALING

	Lab Model		Field
Height	0.153m	X 200	30.5m
Time	1.0 min	X 200^2	40,000 min 27.7 days
Area	$(0.54m)^2$	X 200^2	$(108m)^2$ 1.17 ha
Volume	1 cc	X 200^3	8 X 10^6 cc $8m^3$
Rate	1 cc/min	X 200	200 cc/min 0.288 m^3/day
Permeability (Vertical)	25 μm^2	÷ 200	0.125 μm^2

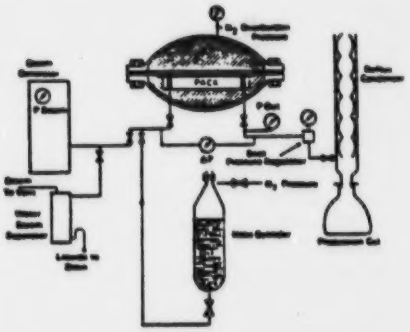

Fig. 2 - Equipment schematic

9.5 mm thick, Buna-N rubber gasket, backed with a 0.6 mm 316 stainless steel diaphragm. O-rings on top and bottom of the diaphragm seal the nitrogen which is used to pressurize the sandpack. The pressure vessel can be rotated to facilitate access and cleaning. There are nine access holes through the vessel and the stainless steel liner to the sand pack. They can be used for injection and production wells or for temperature observation wells. In the latter case, the wells are blind and bundles of up to seven iron-constantan thermocouples are inserted. There is a stainless steel coil below the sand pack, which is used for (steam) heating prior to oil saturation and (water) cooling after a run.

Injection and production wells are custom made for each test from 6.4 or 4.8 mm OD stainless steel or Hasteloy tubing. Completions are made by slotting the tubes crosswise and silver-soldering 100-mesh wire screens over the slots. Steam circulation exit tubes are insulated 4.8 mm OD tubing without slots or screens.

The production system controls the rate of flow with a back pressure regulator in series with a downstream manual valve. It includes one or more reflux condensers to condense the steam and cool the produced water and oil which are collected into 2-liter vessels.

The oil saturation system is a heated and pressurized Hoke cylinder with a capacity of 7 liters which is sufficient oil to saturate the model. Two custom made 7.5 kW electric mantle heaters fit the top and bottom half of the pressure vessel. They assure uniform heating of the sand pack during oil saturation.

Auxiliary equipment includes a datalogger, temperature printer, analog temperature recorders, heating tapes, temperature controllers and pressure indicators.

5. PROCEDURE

Preparations for a model run start by fitting injection, production, and thermal wells into the clean model. Then the model cavity is packed with a slurry of sand and isopropyl alcohol yielding a 34-40% porosity pack. Ottawa sand of 50/70 mesh is used in all tests except in #1 where it is 40/60 mesh. The pressure vessel is assembled and nitrogen sealing pressure applied before the alcohol is removed by gravity drainage followed by forced air drying. After the pack is evacuated, distilled water is slowly imbibed, wetting the sand and providing a check on the model pore volume. Next, the electric mantles heat the pack to 120°C preparatory to oil saturation. Steam heating through coils below the pack can speed up this heating. Thermal expansion of the pore water is relieved by a back pressure regulator which also prevents it from boiling by keeping the pack above steam pressure. Heated oil is then injected into and water produced from the pack until oil breaks through. Due to the favorable mobility ratio of the Surmont crude to water, the resulting oil saturation is uniform; it ranges from 84 to 93 percent by pore volume. While the model is cooling, the saturation system remains pressurized and heated to compensate for thermal shrinking of pore fluids. If fractures are needed, they are installed at this time by removing a thin slice of tar sand (3.2 mm for most horizontal fractures, 5 mm for vertical ones) and replacing it with water saturated sand. Finally, the steam generator and the reflux production condenser are connected.

To begin a run, the model is at room temperature and the operating pressure of the steam generator is set at 2.1 MPa, implying a steam temperature of 216°C. The generator is started and blown-off through the steam-water separator until the pressure stabilizes. Meanwhile, thermocouple bundles are installed and checked and production flasks are weighed. The back pressure regulator is set to control the rate of fluid production, usually around 50 m^3/day (in field scale). During steam injection, pack temperatures are logged and produced fluids are collected. Steam is rerouted from circulation mode to flood mode if and when required. When oil production falls to near zero, or run time becomes excessive, the wells are shut in and the pack is left to cool overnight or forced-cooled by injecting cold water into the coils below the pack.

After cooling, the pressure vessel is disassembled and the sand pack cored to obtain final oil saturations. The formation is removed by layers for a visual and photographic inspection of the steamflooded regions. The model cavity is cleaned, inspected for damage, and repaired if needed.

Production cuts are weighed, the water is removed by decanting and drying, and the remaining oil is weighed. The data of the oil and water cuts, the final oil saturations and the recorded temperatures are used to evaluate the steamflood's performance. Production histories are plotted, including cumulative oil production and instantaneous and cumulative water/oil ratios. Cumulative oil/steam ratios are calculated and plotted against time as well as against cumulative produced oil. Temperature data are used in a computer program to generate isotherms in two vertical cross-cut planes; this is especially useful for tracking the growth of the steam zone with time.

6. TEST CONFIGURATIONS

Ten scaled steam injection tests are described here. They represent three types of geometries: linking between wells without fracturing (2 tests), linking between wells with fracturing (4 tests), and circulating through a single, horizontal well with and without fractures (4 tests). In all tests, the horizontal wells and fractures are located 5 m from the bottom of the 30.5 m high formation to facilitate good sweep.

6.1 LINKING WITHOUT FRACTURING (2 TESTS)

In Run #1 (Figure 3), steam is circulated through the horizontal injection well until communication is established with the nearby, in-line, vertical production well. In a field operation, return of the circulated steam (and produced fluids) would be through the tubing-casing annulus of the horizontal well. A separate exit tubing is necessary in the model because of the small size of the well diameter.

In Run #2 (Figure 4), steam is circulated initially through the bottom horizontal well in order to take advantage of the fast rise of the steam zone. As soon as linking is accomplished, steam injection is switched to the top horizontal well and the formation is steamflooded downward to improve steam sweep efficiency.

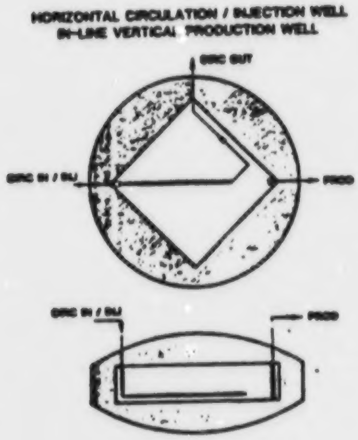
HORIZONTAL CIRCULATION / INJECTION WELL
IN-LINE VERTICAL PRODUCTION WELL
CIRC OUT
CIRC IN / INJ
PROD
CIRC IN / INJ
PROD

Fig. 3 - Configuration - Test no. 1

6.2 LINKING WITH FRACTURING (4 TESTS)

In all Runs (#6, #8, #9 and #10: Figure 5), a horizontal fracture is placed low in the formation to link the injection well with the production well. The wells are horizontal or vertical; the four tests cover the four possible combinations. A vertical fracture is not considered for linking because the steam would promptly rise to the top within the fracture. Consequently, the bottom portion of the sand would be bypassed and poor steam sweep efficiency would result.

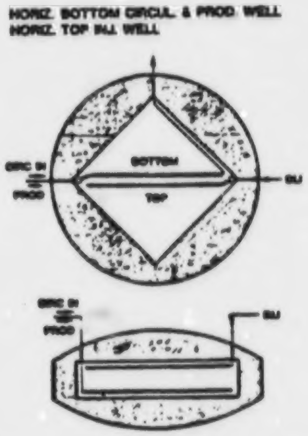

Fig. 4 - Configuration - Test no. 2

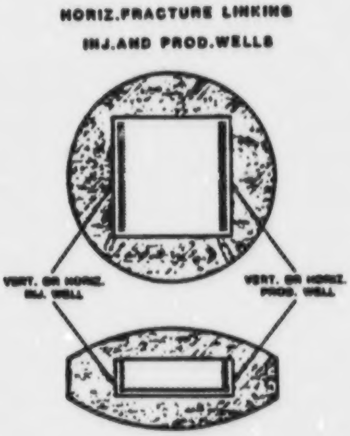

Fig. 5 - Configurations
Tests no. 6, 8, 9, 10

6.3 STEAMING A SINGLE, HORIZONTAL WELL

In Run #1, we discovered that circulation of steam through a fully perforated well (down tubing, with return through the annulus) not only heats the formation but also recovers significant amounts of oil. To explore this configuration in more detail, four tests of steam circulation in a single, horizontal well were added: without fractures (Run #3, Figure 6), with one longitudinal vertical fracture (Run #4, Figure 7), with three transverse, vertical fractures (Run #5, Figure 8), and with one horizontal fracture (Run #13, Figure 9). The horizontal well is completed over its full (horizontal) length except in Run #5 (3 transverse fractures) where restricted entry at the fracture points is thought to be more realistic. In all four runs, exit of the circulated steam (and production) is through a separate exit tubing because there is insufficient room in the model well to accommodate a return annulus which would be present in the field.

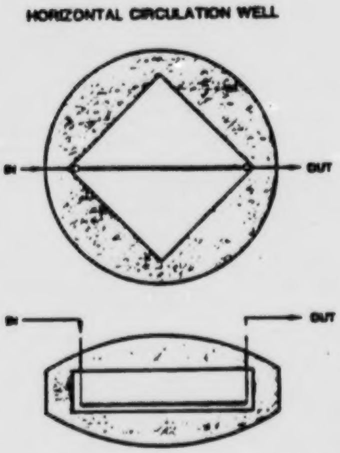

Fig. 6 - Configuration - Test no. 3

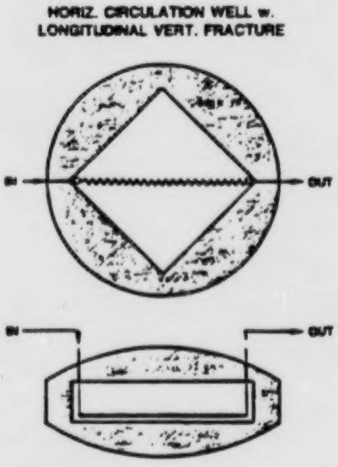

Fig. 7 - Configuration - Test no. 4

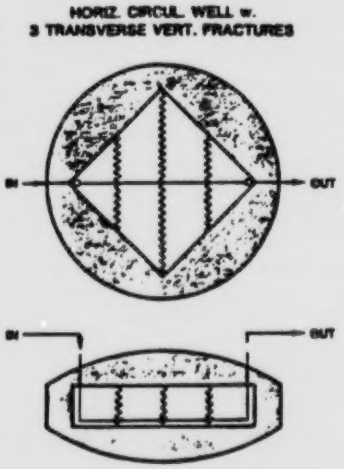

Fig. 8 - Configuration - Test no. 5

7. DISCUSSION

Below we detail an example run, compare results of different geometries, compare the present study with earlier model work on steaming through a bottom water, and finally, discuss two model deficiencies.

7.1 EXAMPLE RUN

Since all tests show similar qualitative behavior regardless of the configuration of wells and fractures, we discuss only one typical experiment: Run #4. It had a horizontal circulation well with a vertical fracture along its length as might occur in the field. (See Figure 7 for geometry.)

When injection is started, steam flows through the injection well, condensing along the way and heating the formation next to the well. After the tar is sufficiently mobilized, the steam enters the formation at the upstream end and drives the tar downstream into the well whence it is produced. After one year, the isotherms (Figure 10) show that the steam zone has already grown considerably upward and downstream, but only slightly sideways from the horizontal well and vertical fracture. Cumulative oil-steam ratio (OSR, Figure 13) is low (0.14); water-oil ratio (WOR, Figure 14) is high (7.1).

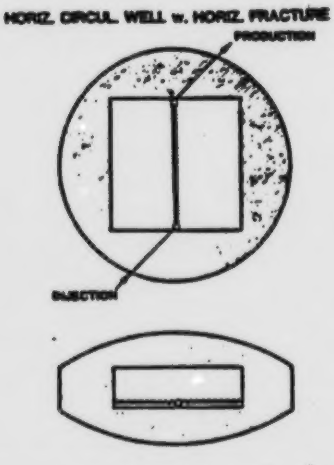

Fig. 9 - Configuration - Test no. 13

One year later, after two years of steaming, the temperature contours (Figure 11) indicate that the steam zone has continued to expand upward in the fracture, very slightly sideways, and virtually not at all downstream. Cumulative OSR (Figure 13) and instantaneous WOR (Figure 14) have changed little.

Later yet, at four years into the flood, the steam zone has swept most of the fracture height above the well (Figure 12). Crosscut isotherms (Figure 12, bottom) confirm that the steam zone has nearly reached the top but its width is much less than its height. Yet, cumulative OSR (Figure 13) has reached the 0.2 level, which it will surpass

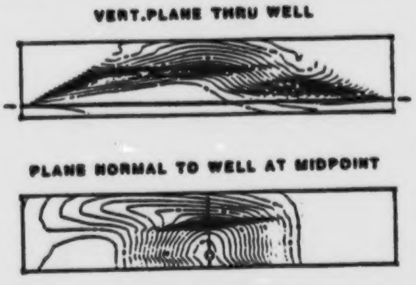

Fig. 10 - Isotherms after 1 year - Test No. 4

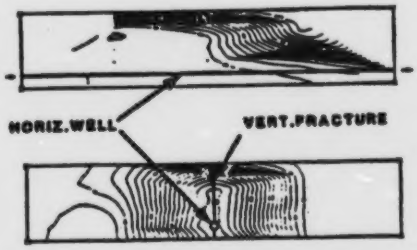

Fig. 11 - Isotherms after 2 years - Test no. 4

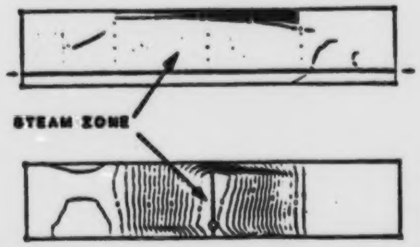

Fig. 12 - Isotherms after 4 years - Test no. 4

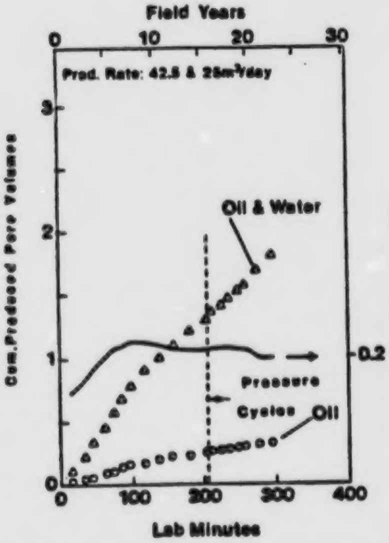

Fig. 13 - Production history - Test no. 4

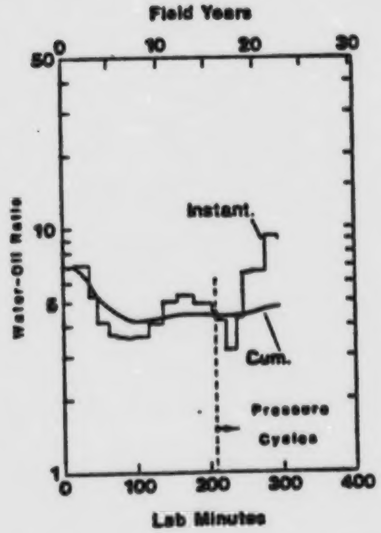

Fig. 14 - Watrr-oil ratio - Test no. 4

throughout the remaincer of the test. Instantaneous WOR (Figure 14) has dropped to 4.1 and will go lower yet in the next four years. This production behavior indicates that the steam zone must have broadened considerably along the upstream half of the vertical fracture. There are no temperature data to verify this, but post-run, visual inspection of the sand pack confirms it. Production rate was dropped after eight years to improve the OSR, but this failed. After 16 years, injection pressure was varied with time for several cycles in order to benefit from the more efficient oil displacement during the pressure blowdown phase. No effect is apparent other than continuation of established trends (Figures 13 & 14). We think that scaling of the pressure cycles was inadequate.

The final plot for this test (Figure 15) is well suited to show how the cumulative oil-steam ratio varies with the cumulative amount of oil produced (expressed as % of Oil-Originally-In-Place); lapsed time is ticked in on the curve. The plot shows that OSR for this geometry rises slowly, reaching the 0.2 level after four years with about 7% of the OOIP recovered. Thereafter, the cumulative OSR remains fairly constant until the test was terminated after 22 years of steamflooding. Only 35% of OOIP is recovered, confirming that a vertical fracture is not the ideal orientation for steamflooding.

Note that it takes increasingly longer to recover incremental percentages of oil, reflecting the slow-down in growth of the steam zone. Also note that the pressure cycling again shows little effect.

7.2 COMPARISON OF RUNS

In Figure 16, cumulative oil-steam ratio is plotted against cumulative oil recovery for all ten tests.

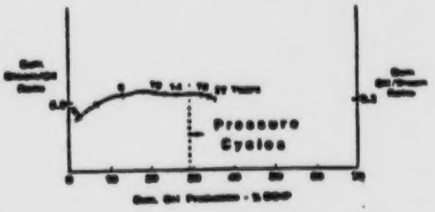

Fig. 15 - Oil-steam ratio vs. oil production
Test no. 4

If an OSR of 0.2 is accepted as the lowest economically tolerable value, then it is encouraging that nine configurations reached this minimum and only one fell short. Furthermore, and of equal significance, the ultimate oil recovery exceeded 50% of OOIP in six of the ten tests. We conclude that steaming through horizontal wells is a viable concept: it allows recovery of significant amounts of oil at acceptable oil-steam ratios.

7.2.1 Linking Wells Without Fracturing

In both runs, steam was circulated through one horizontal well to heat and mobilize the Surmont oil until communication with another well was established; then a steam drive was initiated between the two wells. It appears that thermal conduction (run #1), even when augmented by gravity rise of the steam zone (run #2), is simply too slow to be relied on for linking. Instead, one should fracture the formation. However, substantial amounts of oil were produced during steam circulation, establishing it as a recovery method.

7.2.2 Linking Wells With Fracturing

In all four runs, the tar sand was steamflooded from a horizontal or vertical injection well to a horizontal or vertical production well through a linking, horizontal fracture. All tests show high cumulative oil recovery at favorable oil-steam ratios. However, performance is strongly dependent on the orientation of the linking fracture. Recent field monitoring of steam-induced fractures seems to indicate that these can turn horizontal even if they began vertically. It is thought that the alteration of the tectonic stress field by the superposed thermal stress field is conducive to a horizontal orientation. Furthermore, the horizontal direction of injection and/or production wells may facilitate the making of a horizontal fracture.

7.2.3 Steaming a Single, Horizontal Well

In these four tests, steam was circulated through a horizontal well, with and without horizontal or vertical fractures. Results depend strongly on the presence and orientation of fractures, with the best configurations recovering more than half of the oil-in-place at an acceptable oil-steam ratio.

The single horizontal well without any fractures possesses the elegance of simplicity. Its performance does not depend on the proximity of a production well or on the successful linking with one. It is also easiest to interpret because no uncertainties exist about the existence, number, extent, and orientation of fractures. For these reasons, we recommend it for field testing.

7.3 COMPARISON WITH STEAMING THROUGH A BOTTOM-WATER ZONE

Results of the present series of tests compare favorably with previous work [3] on steaming through the bottom-water zone in a Wabasca tar sand. That study, conducted in the same laboratory model, on the whole showed lower oil-steam ratios. This is only partially attributable to the much higher (kinematic) viscosity of Wabasca tar (5 million mm²/s @ 13°C). The rest of the difference in performance is a consequence of the steam-heated bottom-water zone acting as a flow channel for the mobilized tar. This requires a tar saturation at or above the residual level of 15%, which will never be recovered.

Also, in the Wabasca model tests, it was found that steam rate greatly affected oil recovery. Steam rate should be expected to affect results in the present study, but the scope of the program did not permit its inclusion. It is recommended for future work, possibly by numerical simulation.

7.4 SCALED MODEL DEFICIENCIES

It has already been pointed out that capillary forces are not scaled accurately and that their effect on the steam process is minor because the viscous forces are so large. Two other model characteristics must be dealt with: high initial oil saturation and near-perfect sand homogeneity.

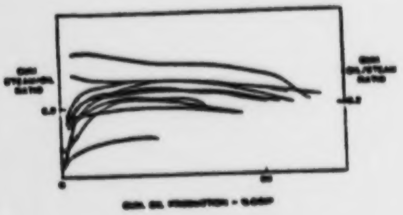

Fig. 16 - Oil-steam ratio vs. oil production
All tests

By virtue of the flow saturation method employed in the laboratory, oil saturations in the model tend to be in the range of 84-93%. This is significantly higher than in the field where oil saturation rarely exceeds 75%. As a consequence, model results are optimistic and should be adjusted when scaling up to field applications.

The model sand pack is homogeneous so it has isotropic permeability. But in most tar sands, the horizontal permeability is several times larger than the vertical one. The vertical permeability is scaled in the model because of the importance of gravity rise of the steam zone and gravity drainage of oil. It follows that horizontal permeability in the model is too small. Consequently, sideways spread (broadening) of the steam zone in the model is smaller than in the field. In this sense, model results are conservative. On the other hand, nearly impermeable horizontal layers often occur in field deposits, e.g. the calcareous bands in the Wabasca tar sand. Such barriers, if continuous, arrest the gravity rise of the steam zone from the horizontal well to the top of the formation. In the model, barriers were not investigated, but their presence in a deposit should probably preclude the use of horizontal wells and fractures.

8. CONCLUSIONS & RECOMMENDATIONS

- More than half of the OOIP is recovered in six of the ten configurations investigated; cumulative oil-steam ratio surpasses the 0.2 level in nine. Results vary significantly with geometry.
- Linking without fracturing, i.e. by conductive heating takes too long to be practical; fracturing is recommended.
- Linking with horizontal fracturing is a practical and efficient means to obtain injectivity for steamflooding in an immobile tar sand.
- Circulating steam through a single, horizontal well recovers significant amounts of oil at reasonable oil-steam ratios. The simplicity of the geometry and the unambiguity of interpretation of results recommend it for field testing.
- Model results are optimistic insofar as initial oil saturation is higher than in the field; they are conservative with regard to sideways growth of the steam zone because horizontal permeability in the model is lower than in the field.
- Temperature measurements, combined with contour (isotherm) mapping, serve as a valuable diagnostic tool to track the growth of the steam zone and the mobilized tar zone.
- The effect of steam rate should be investigated; numerical simulation is recommended.

9. ACKNOWLEDGMENT

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JUNE 26 – 29, 1984
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PHYSICAL SIMULATOR FOR
HORIZONTAL WELL

By

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ABSTRACT

Laboratory simulation of a steam stimulation process using a horizontal well implanted into a tar sands formation was required in order to support field projects. Use of liquid solvents and non-condensable gases as additives, in conjunction with steam was regarded as another part of the experimental study. A double walled, 1 m long, pressurized Hassler-type cell was designed in order to simulate overburden pressure on the tar sands. Actual tar sand was used and packed around a scale-reduced horizontal well. This paper details major sub-systems of the physical simulator and describes the complex data processing and the software used to compare different runs.

INTRODUCTION

An estimated 38 billion cubic meters of bitumen in the tar sands of Northern Alberta is lying in formations too deep for surface mining. In situ recovery techniques are required to extract the bitumen from these deposits. The mobilization of the highly viscous bitumen having more than 1 x 10^6 cP at the reservoir temperature of 5°C requires the injection of heat into the formation.

The use of vertical wells to inject fluids such as steam or hot water and to recover the production fluids, is well documented and is in practice today. The recent development of controlled directional drilling[1,2,3,4,5,6] offers the possibility of using long deviated wells in the in situ recovery process. Different patterns containing a combination of vertical and horizontal wells have also been recently considered in the literature[7,8,9].

Texaco Canada Resources is carrying out a field experiment in the Athabasca field involving deviated wells[1]. To support their field project, Texaco Canada Resources contracted the Alberta Research Council to carry out a program of laboratory investigations. For this purpose a cylindrical, 1 m-long, physical simulator was developed. This paper describes the simulator, the support instrumentation, the processing of results, and its limitations and advantages. An analysis of the results based on the laboratory investigations using this simulator were presented elsewhere[10,11,12].

AREAS OF INTEREST

The laboratory investigation responded to the following practical problems:

a) Will a slotted horizontal liner be able to stimulate an oil sand formation and drain the produced oil?

b) Is the relative position of the well in the oil sand formation important?

c) Will solids production be a major problem in the horizontal well?

d) Which is the most efficient mode of fluid injection, continuous or cyclic?

e) Will the use of additives increase oil recovery?

OBJECTIVES

The design and operation of the horizontal well simulator had to meet several objectives in order to obtain meaningful results for the areas of interest. These were:

a) The experimental rig had to be able to simulate unconsolidated reservoir conditions to approximately 100 m in depth.

b) The rig needed to be versatile enough to study different processes (huff & puff, steam flood, hot water flood).

c) The simulator must be able to accomodate various types of well completions and different solid control techniques.

d) The support instrumentation and control system must be able to accomodate and measure different injection fluids and additives, gases and liquids at a predetermined temperature, pressure and flow rates.

e) The rig must have a production system which is able to separate liquids, vapour and gas phases without changing the nature of the produced fluids.

f) Experimental data such as temperature, pressure and flow rates must be accurately measured and logged.

DESCRIPTION OF SIMULATOR

The simulator used is a double-walled pressurized Hassler-type cell (Figure 2) which incorporates a rigid high pressure outer wall and a flexible lead sleeve inside wall. The oil sand is initially packed into the inner lead sleeve onto which end caps are soldered. This assembly is then packed into the rigid pressure vessel and nitrogen pressure is applied to the lead sleeve. This results in triaxial loading and simulates overburden pressure on the oil sands.

Injection and production piping are fed through the outside wall and connected to the inside pack. Thermocouple strings are inserted into the oil sand and terminate outside the cell. A "MACSYM II" process control computer monitors and controls the process. The individual components of the simulator are described in detail in the following subsections (See Figure 3).

Rigid Pressure Vessel

The pressure vessel (1) used in the horizontal well investigation is a high pressure cylindrical vessel (approved to operate at a maximum pressure of 11,300 kPa and 340°C). It is constructed from two semi-elliptical flanged end caps and a spool consisting of a 1.1 m piece of pipe with flanges at both ends. Inside overall dimensions are approximately 150 cm in length, including the end caps, and 40 cm in diameter. Each end cap is provided with twenty-one 1 in. to 3/8 in. NPT threaded holes for the thermocouple leads, electrical wires and process piping. The cell is mounted on a stand which allows it to be positioned at any angle of inclination.

Lead Sleeved Pack

Approximately 100 kg of tar sand is packed into a 1.6 mm thick lead sleeve and sealed at each end by a brass end cap which has the appropriate fittings mounted in them to allow the injection and production of fluid. The dimensions of tar sand in the pack are 100 cm in length and 25 cm in diameter. The pack is formed by tamping small layers of oil sand inside the lead sleeve which is held in a steel mold. This procedure produces a uniform density of approximately 2 gm/cm . The injection and production wells are secured in their appropriate positions while packing takes place. Various types of wells have been used, depending on the objectives of a run. Some examples of the completions tested are: a slotted pipe of various sized and shaped slots, a slotted pipe containing frac sand, a slotted pipe with an external, consolidated filter element; and a frac sand communication path of various-sized sand.

Brass fittings are soldered to the lead sleeve at pre-determined positions. Through these multi-point thermocouple strings are inserted into the pack and sealed.

Considerable effort is needed to ensure that the oil sand pack is perfectly sealed. This is achieved by good packing of the tar sand, careful soldering and a detailed testing program.

Overburden System

Nitrogen gas is used in the inner void space of the double-wall cell to simulate the overburden. It is supplied to the cell from pressurized cylinders where a reducing/relief pressure regulator (26) maintains the pressure at the desired value. A bleeding valve system and an overpressure security device is provided.

Injection System

There are four injection systems incorporated within the simulator (Table 1), having the following particulars:

Steam Injection

Steam, at approximately 4450 kPa, is piped through a system of headers, manifold and control valves to an injection pipe into the sand pack and to other utilities required for the simulator. Upon reaching the cell, the

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(#) refers to parts in Figure 3.

steam goes through a water knockout vessel (4), a 4 kW heater (5), two parallel turbine flow meters (6) and a final control valve which throttles the steam to the desired operating pressure. The steam is then manifolded to either end of the oil sand pack (see Figure 2, configuration A or B) or bypassed to the production system.

Liquid Injection

The liquid to be injected is stored in two parallel supply tanks (22). Nitrogen is used to pressurize these tanks and provide the required liquid supply pressure. A mass flow meter, a control valve (8) and an immersion heater (8) assure the control of the injection conditions (temperature, pressure and flow rate).

Solvent Injection

Solvent is added into the injection steam or liquid from a supply tank (22) with a gas cap of the appropriate pressure. The solvent flowrate is measured by an orifice and adjusted by a control valve (21). The solvent flows through a steam jacket where it can be preheated.

Gas

Gas additives can be injected into the steam and liquid flow from gas cylinders (24) having a pressure reducing regulator. The flow is measured by a mass flow meter and adjusted by a control valve (25). The gas flow can be preheated by passing it through a steam jacket.

Production System

Produced fluids are collected in a heated 5 liter gas/liquid separator (9). An ultrasonic level sensor controls the liquid in the separator between a high and low level by actuating an on/off release liquid valve. The separator temperature is maintained at the measured production temperature by a 1000 watt heater (10) coiled around the exterior of the vessel. Thus the separation takes place at the true production temperature and pressure. Liquid leaves the bottom of the separator through an on/off valve into an atmospheric collection vessel named "Production A" (16). The volume of liquid released is approximately 12% of the total volume of the separator resulting in a minimal presure drop when liquid is dumped. Any liquid which is flashed by the resulting pressure drop is recondensed in an attached condenser (14). Vapor present in the production fluid exits from the top of the separator, through a control valve and into a condenser and is collected in the collection vessel (12) named "Production B" (15). Any non-condensable gases present in either phase of production will flow through the top of the condenser to be measured on wet test meters (19). A port for taking gas chromatograph samples is available at this point (18).

In processes where there is no vapor in the production fluids, back pressure can be applied with nitrogen. This is done through a pressure reducing relief regulator (13) attached to a nitrogen gas cylinder and connected to the separator.

INSTRUMENTATION

Tables 2 and 3 describe the measuring sensors and the control loops used in the horizontal well simulator. Outputs from the above devices are conditioned and displayed on various instruments (voltmeters, digital thermometers, chart recorders) for observation during the run. Data are also recorded and stored on magnetic tape.

Control of the process is accomplished by a combination of electronic controllers and the "MACSYM II" computer. The following is a description of the various control loops:

a) Steam injection pressure is controlled by an electronic proportional-integral controller operating a pneumatic control valve. For constant pressure processes the set point is locally set at the controller. For cyclic processes the set point is by the computer according to a preprogrammed cycle.

b) The mass flow rate of the injected steam is controlled by an electronic proportional-integral controller with a local set point operating a pneumatic control valve in the vapor phase of the production system. The value of the mass flow rate is calculated by the computer from the volumetric flow rate measured by the turbine meters and the pressure and temperature at the meters. The turbine meters are calibrated before each run to obtain a relationship between frequency and volumetric flow rate at the operating temperatures and pressure. The equations used for calculating mass flow rate are as follows:

$$V = A \times F + B$$
$$S = (T/T^1) \times S^1$$
$$M = V/S$$

where:

V = volumetric flow rate
F = turbine frequency
A,B = turbine calibration constants
T = actual temperature
T^1 = saturation temperature at operating pressure
S = specific volume at operating pressure and temperature
S^1 = specific volume at saturated vapour
M = mass flow rate

c) Temperature of the injected steam is controlled by an electronic proportional-integral controller operating a 230 V AC voltage controller connected to a 4 kW immersion heater. This heater maintains the steam to a superheat of 25°C.

d) Flow rates of the injected liquid and solvent are controlled by the computer. A mass flowmeter and an orifice meter measure the flow rates of the liquid and solvent, respectively. The control is a proportional integration using the following equation:

$$E = S - V$$
$$I = I + E \times R/V$$
$$M = G \times (E + I)$$

where:

S = setpoint
V = measured variable
G = gain
R = reset rate in repeats/min.
V = update rate in updates/min.
M = output to control device

e) Gas injection flow rate is controlled by a integral mass flow meter, electronic controller and electronic valve. The set point for the controller is generated by the computer according to a present gas flow rate/liquid flow rate ratio required for each run.

f) Liquid injection temperature is maintained by a 3.5 kW immersion heater in the injection line. This is controlled by an electronic proportional-integral controller and a 230 V AC voltage controller.

DATA ACQUISITION AND DISPLAY

The following devices record and/or process numerical information collected from the sensors during a run:

a) All measured parameters and elapsed run time are scanned by a "Fluke" data logger and recorded on magnetic tape. For fixed injection processes, the scan intervals are fixed. For cyclic processes, the scans are initiated from the computer at the top and bottom of the cycles. Temperatures are recorded in °C and all other parameters are recorded in DC volts and require conversion to their appropriate units.

b) Data required by the operator to supervise the run are scanned, processed, averaged over approximately 1.5 minute intervals, printed out, and recorded on magnetic tape by the the MACSYM II computer. This enables the operator to have real time information on pressure temperature, mass flow rate, cumulative mass and degree of saturation of injected and produced fluids.

c) Two strip chart recorders display a continuous log of twelve parameters. These show the response of the oil sand pack to the particular process used in a run. These parameters are: injection temperature, pressure, flow rate, and characteristic temperatures throughout the pack. Figure 4 gives an example of this display.

LABORATORY ANALYSES

A routine laboratory analyses is done for each run using a "Dean Stark" extraction procedure. The analyses on a pre-run sample of the oil sand used to construct the pack, on the produced fluids and on post run samples taken from the depleted pack. Weights of the bitumen, water and solid components of each sample are produced and used in the material and energy balances.

POSTRUN DATA PROCESSING

Raw data recorded from each run and laboratory data of sampled fluids are processed using a standard procedure on a Tektronix graphic computer system (desk top computer, disk drive, plotter). In this way, different runs can be compared easily. The following is a list of data processing which is performed on a routine basis:

Material Balances

A balance of initial conditions and injected and produced fluids is done on a basis of time, weight and chemical analysis. Figures 5A to I give an example of the plots resulting from such a balance.

Energy Balances

Energy balances are computed from the temperature, pressure and rate of injected and produced fluids. Examples of these balances are presented in Figures 5J to L.

Temperature Profiles

From the temperatures measured from the thermocouple grid, isotherms are constructed. Profiles (Figure 6) at various times throughout the run are produced to give an indication of the development of the temperature.

Bulk Temperature

For comparative use, a bulk temperature is calculated by an average of all thermocouples. A comparison could only be made between runs that had the same thermocouple grid. The value is plotted versus time and percent recovery to give an indication of the importance of the temperature in the process.

Recovery Profiles

Recovery profiles are constructed by laboratory analysis of post run samples taken from various locations in the pack. The residual oil is then compared to the initial oil in place. These profiles give an indication of the symmetry and sweep of the process.

Isochronal Profile

For runs in which the process included cyclic injection-production stages, profiles (Figure 7) are made of the times at which the temperatures start to oscillate in phase with the cyclic injection temperature. This profile shows the progression of the convection zone or initialization of bitumen mobilization in a huff and puff process.

LIMITATIONS OF THE SIMULATOR

1) One of the main limitations of the horizontal well simulator is in the comparison of the absolute results obtained from it and those of the field. It must be realized that certain characteristics of the model are scaled (13) to that of the field, such as physical size and rates of injected and produced fluids. Other characteristics such as the structure of the oil sands are close to those found in the reservoir. The usual approach is to compare the trends and rates between similar processes.

2) A problem encountered in the rig is the great difficulty in sealing the pack from the overburden. This problem has been solved by extensive quality control in the construction of the pack.

3) Another problem encountered in designing the rig was an accurate measure of steam flow rate. Two turbine meters with ball bearings are used in parallel. Although the operating conditions are at the limit of the bearings and they usually burn out before the completion of the run, it is possible to switch from one meter to the other to change the bearing.

ADVANTAGES OF THE SIMULATOR

1) One advantage of the simulator relates to the oil sand in the simulator which is close to that found in the field. By duplicating the well completions used in the field, it is possible to study problems related to control of solids in an unconsolidated formation.

2) The use of a high pressure gas/liquid separator in the production piping is an important advantage of the simulator. Because the separation takes place at the true production conditions, the nature of the production fluids is known--resulting in accurate mass and energy balances.

   The use of the separator also allows control valves to operate on single phase fluids. This results in much better control than would occur if they were to operate on multi-phase fluids.

   The use of ultrasonic level detectors in the separator solves the problem in the viscous bitumen coating and plugging other sensors such as capacitance probes or DP cells.

3) Because of the high level of instrumentation used on the rig, very good control can be achieved. This means that several

runs can be done under near identical operating conditions, changing only those parameters that are of interest.

4) Different configurations to simulate different processes can be easily assembled on the rig. Permanent piping and wiring is made only to the outside of the cell where feedthrough to the inside of the vessel and tubing and wiring connections exist. From this point, various piping and thermocouple arrangements can be constructed.

CONCLUSIONS

The horizontal well simulator is an excellent device for comparing the effects of different in situ recovery processes. The simulator is large enough to be able to study the temperature development and confinement and to measure accurately input-output fluid rates; yet it is small enough for ease of assembly and operation. The rig is instrumentated so that it can simulate various processes and is versatile enough to be piped into different configurations. The symmetry of the well configurations enable it to be easily compared with mathematical models.

The horizontal well simulator can be useful in studying the recovery of solids and fluids transport problems as well as testing solutions to these problems.

ACKNOWLEDGEMENTS

This work, as well as the development of the experimental rig, was sponsored by Texaco Canada Resources Ltd. I would like to acknowledge the special interest and cooperation to the development of the horizontal well simulator and its software, and of Mr. B. Kay and Dr. D. Exall in the early stages of the project; Dr. P. Toma throughout this project; and Dr. T.R. Heidrick during the latter part of the piloting project. Special thanks to Mr. G. Korpany, Mr. E. Rabeeh, Mr. S. Schoon, Mr. A. Stroich, Mr. J. Hruschak and Mr. R. McKinnon who all contributed to the success of the project. Thanks ~~is~~ are also due to L. Pregoda for skillfully typing this paper.

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TABLE 1

MAIN CHARACTERISTICS OF INJECTION SYSTEM

	Flow	Pressure	Temperature
Steam	1.5 - 21.0 l/min	448 kPa max.	500°C max.
Liquid	0 - 50 kg/h	1030 kPa max.	200°C max.
Gas	0 - 50000 sccm	1030 kPa max.	200°C max.
Solvent	0 - 1 kg/hr	1030 kPa max.	150°C max.

TABLE 2

HORIZONTAL WELL SIMULATION - SENSORS

Type	Location	Make/Model	
Pressure	-Supply -Injection -Production -Overburden	Foxboro Pressurure Transmitter E 11 GM	0 - 6.9 mPa
Differential Pressure	Injection-Production (Low Range)	Foxboro D.P. Transmitter E 13 DM	0 - 172 kPa
	Injection-Production (High Range)	Viatran D.P. Transmitter 702	0 - 689 kPa
Flow	Steam Injection	Flow Technology Turbine Flowmeter FTM-5GB	1.5 - 21.0 l/min (calibrated with steam before each run)
	Liquid Injection	Micromotion Mass Flowmeter C.S.	0 - 50 kg/h
	Gas Injection	Hastings Mass Flowmeter HSOK	0 - 50000 sccm
	Solvent Injection	Foxboro D.P. Transmitter with Integral Orifice .02"	0 - 1 kg/h
	Production Condenser Coolants	Micromotion Mass Flowmeter B25	0 - 15 kg/hr
Temperature	-Supply -Injection -Production -Oil Sand Pack -Environment -High Pressure Cell Inside-Outside	Chromel-Alumel Thermocouple(Type K) 3-5 multipoint unit	
Level	Production Fluids	Sensal Ultrasonic Sensor 303 SH	

TABLE 3

HORIZONTAL WELL SIMULATION - CONTROL LOOPS

Name	Type	Typical Set Point	Position on Figure 3	Components
Supply Steam	Pressure	276 kPa	2	Pneumatic Controller/Valve
Jacket Steam	Pressure	345 kPa	3	Pneumatic Controller/Valve
Supply Steam	Temperature	260°C	5	Type K Thermocouple/Electronic Controller/Voltage Controller/Heater Element
Injection Steam	Pressure	207 kPa	7	Pressure Transducer/Electronic Controller/Pneumatic Control Valve/(set point generated at computer)
Injection Steam	Flow	10 kg/h	6	Turbine Meter (conversion to mass flow rate by computer) Electronic Controller/Pneumatic Control Valve
Injection Fluid	Temperature	--	9	Type K Thermocouple/Electronic Controller/Voltage Controller/Heater Element
Production Liquid	Level	--	11	Ultrasonic Sensor/Computer Control/Pneumatic Ball Valve
Production Liquid	Temperature	--	10	Type K Thermocouple/Electronic Controller/Voltage Controller/Pneumatic Ball Valve
Overburden	Pressure	310 kPa	26	Manually Set Reducing/Relief Regulator
Injection Liquid	Flow	5 kg/hr	23	Mass Flow Meter/Computer Control/Pneumatic Valve
Injection Solvent	Flow	1 kg/hr	21	Orifice/Computer Control/Pneumatic Valve
Injection Gas	Flow	2000 sccm	25	Mass Flow Meter/Electronic Controller/Electric Valve (set point generated by computer)

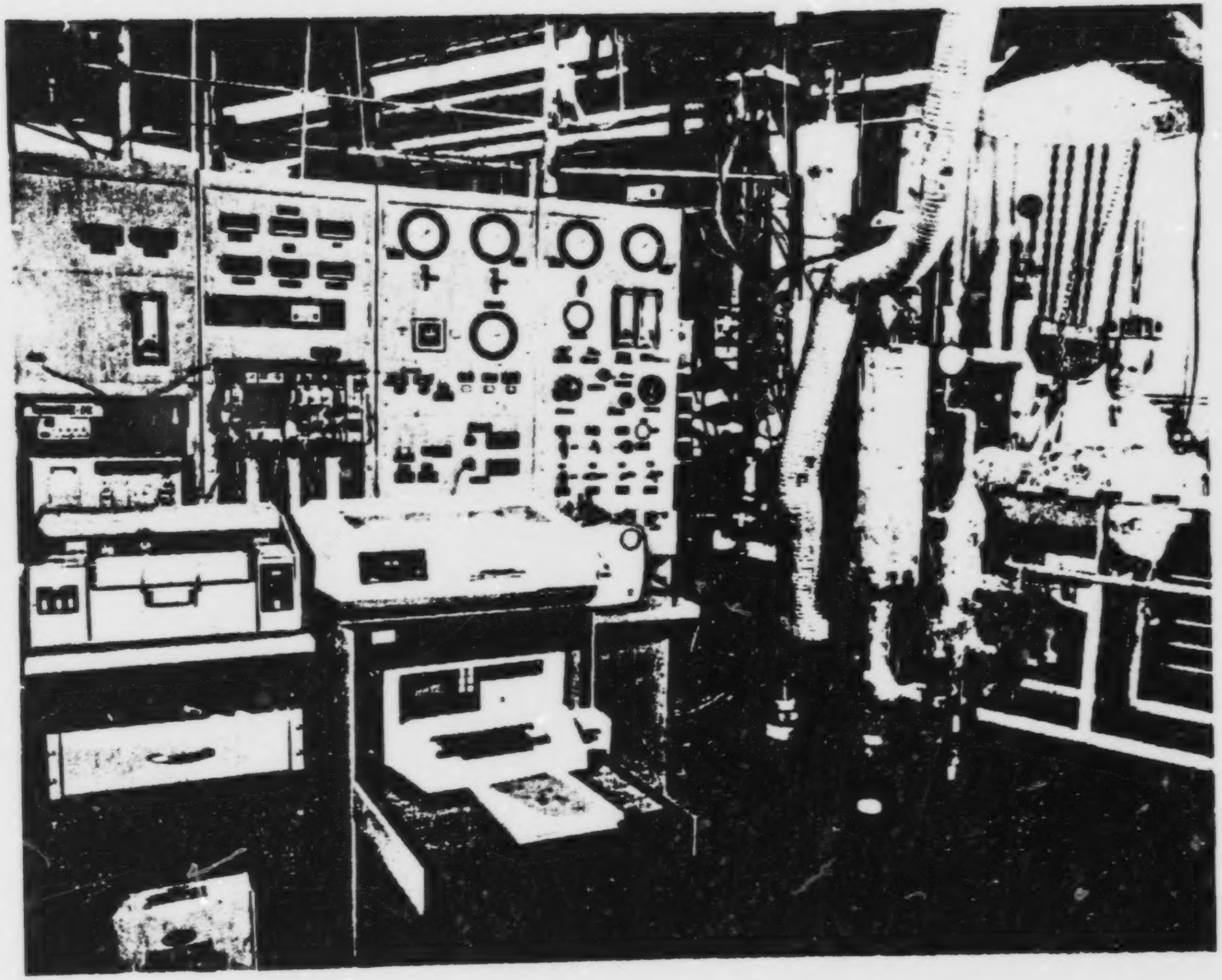

Figure 1. Physical Simulator and Accompanying Equipment

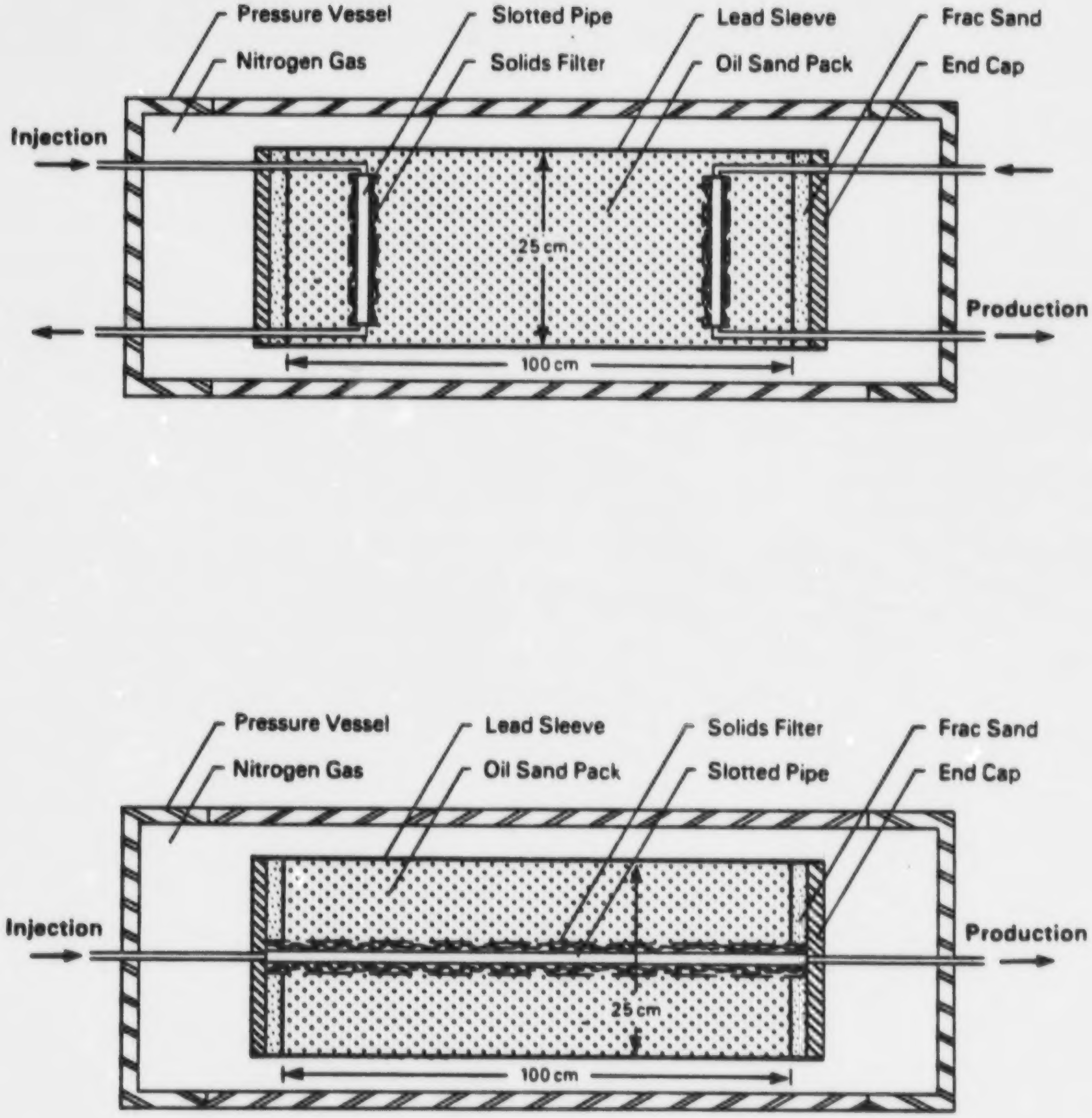

Figure 2. Examples of Two Simulator Configurations Used

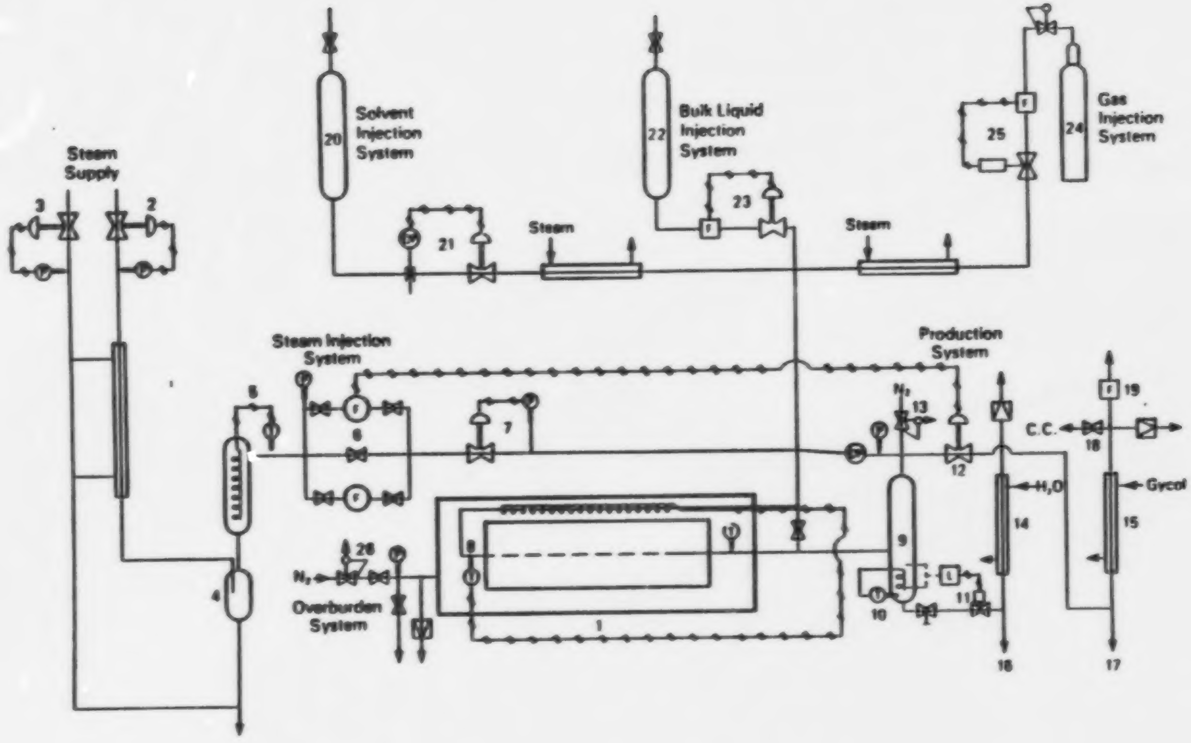

Figure 3. Rig Assembly - Schematic

Figure 3. LEGEND

1) Cell-Oil Sand Pack
2) Injection Steam Supply
3) Jacket Steam Supply
4) Water Knockout
5) Injection Steam Superheater
6) Injection Steam Flow Meter
7) Injection Steam Control Valve
8) Injection Fluid Temperature Control
9) Production Liquid/Gas Separator
10) Production Liquid Temperature Control
11) Porudction Liquid Level Control
12) Production Gas Control Valve
13) Production Back Pressure Regulator
14) Production Liquid Condenser
15) Production Gas Condenser
16) Production Liquid Sample
17) Production Cendensable Gas Sample
18) Production Non-Condensable Gas Sample
19) Wet Test Meter
20) Solvent Supply Tank
21) Solvent Injection Control
22) Bulk Liquid Supply Tank
23) Bulk Liquid Injection Control
24) Gas Supply Cylinder
25) Gas Injection Control
26) Overburden Reducing-Relief Regulator

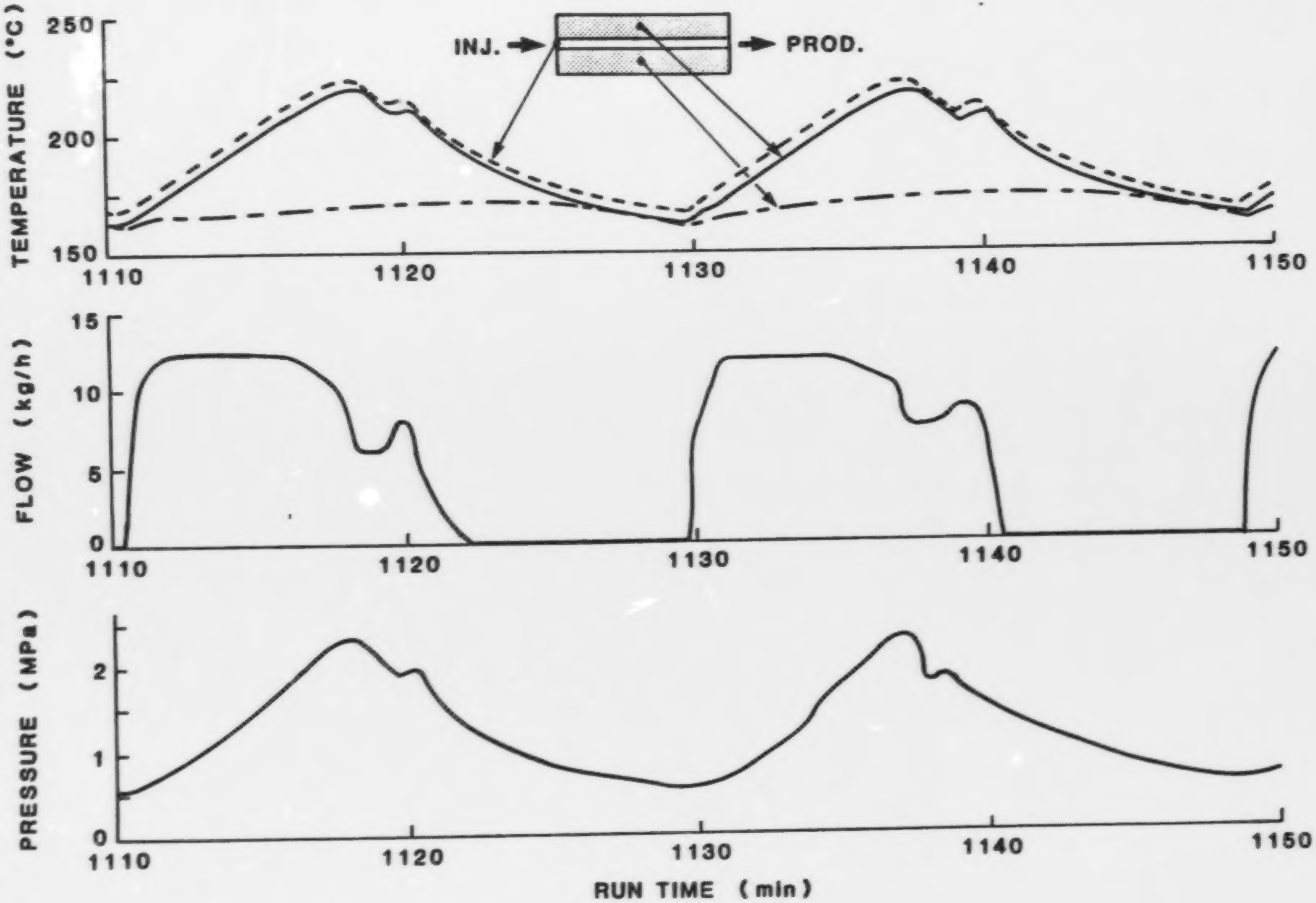

Figure 4. EXAMPLE OF A STRIP CHART

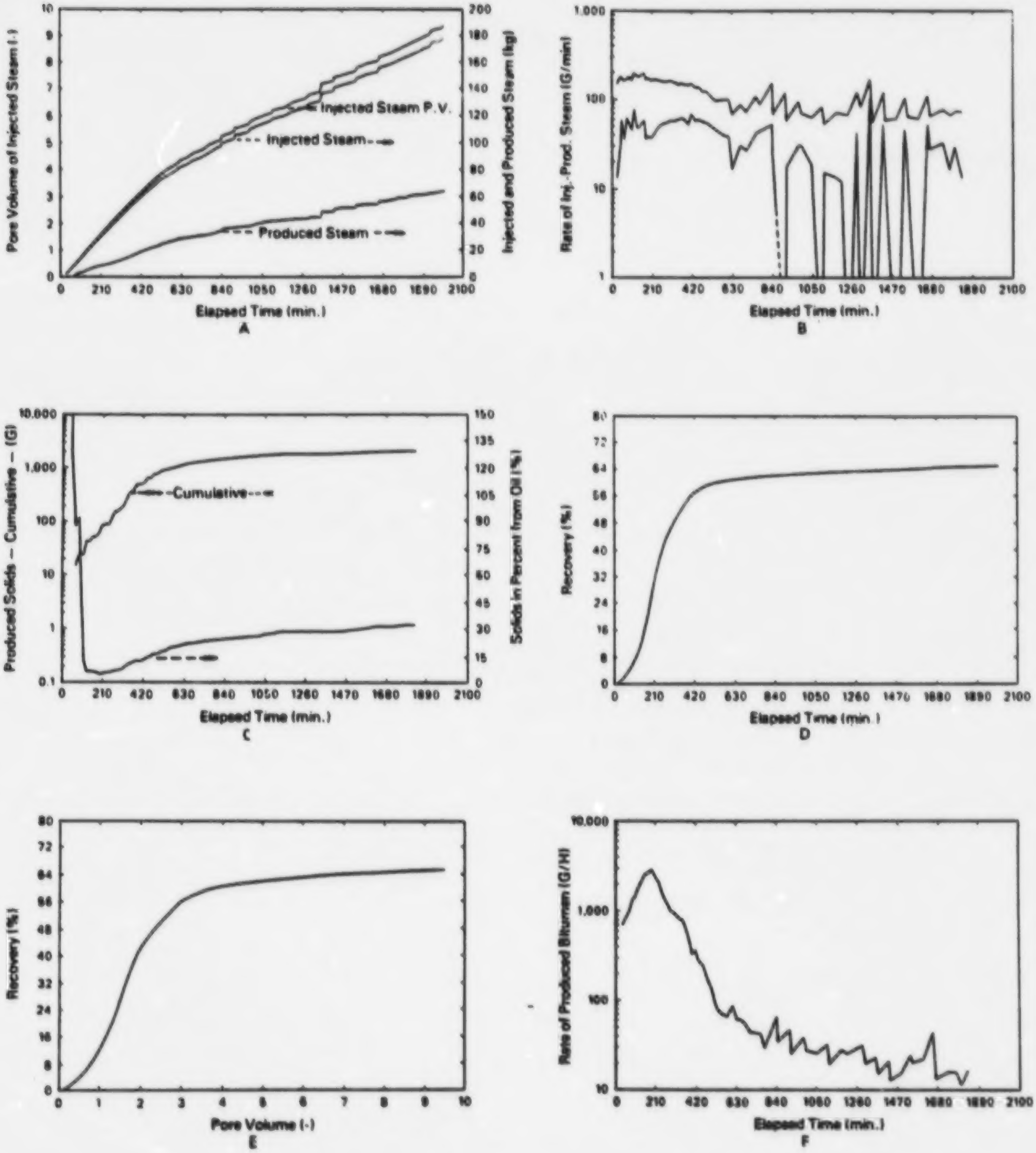

Figure 5. Standard Graphs (A - F)

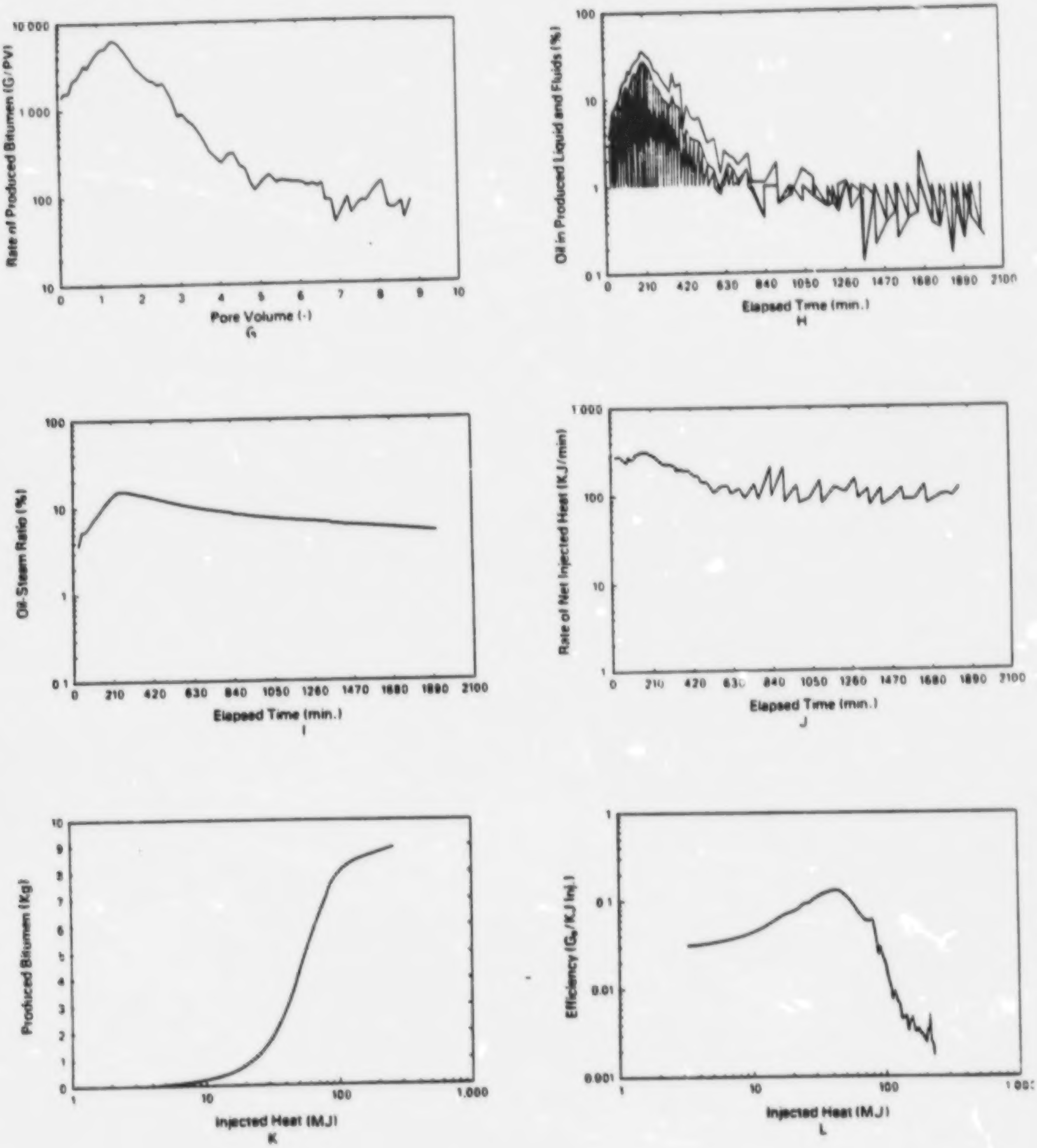

Figure 5. Standard Graphs, Continued (G - L)

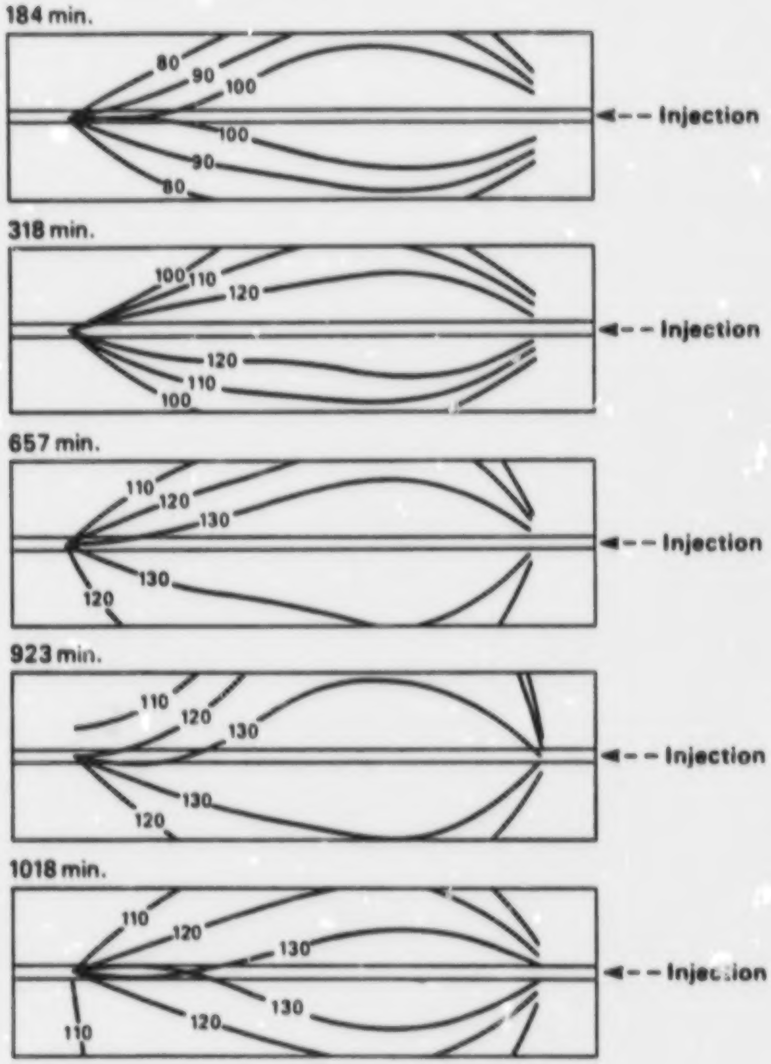

Figure 6. Temperature Profiles

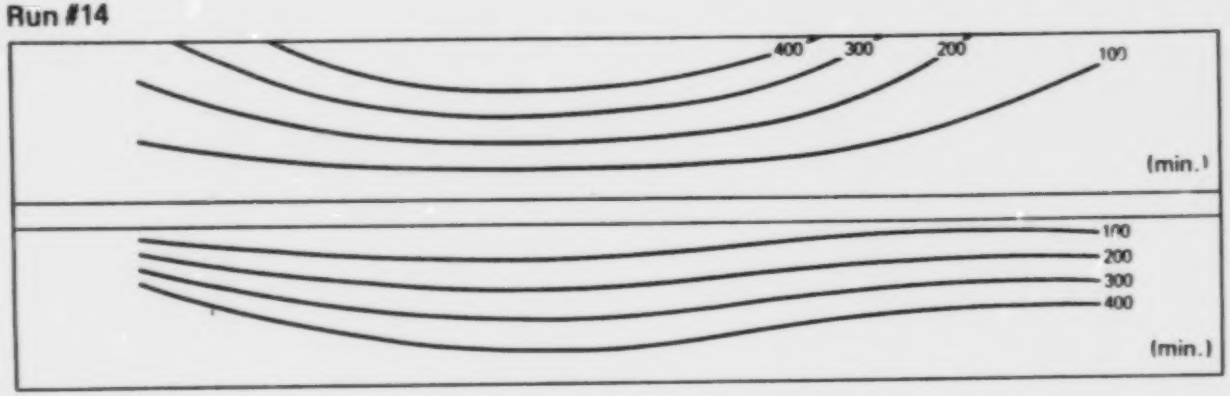

Figure 7. Isochronal Profile

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The laboratory simulation of bitumen recovery by steam stimulation of horizontal wells

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Abstract

A laboratory investigation into the variable parameters which influence production of bitumen from a horizontal well has been carried out at the Alberta Research Council under contract to Texaco Canada Resources Limited during the period 1979-1982.

A reduced scale model of a portion of a horizontal well in an oil sand formation was reproduced in the laboratory. A double walled, pressurized Hassler-type cell was used to simulate overburden pressure on the oil sands. Actual Athabasca oil sand was used. The simulator was fully instrumented and a cyclic stimulation operating procedure was used to produce the bitumen. Steam-alone and steam in conjunction with solvents and noncondensible gases were tested. Alternate production schemes were studied and variations in the completion of the well were made.

The paper summarizes observations made during fourteen different experiments.

A linear regression model using nine parameters measured during the runs is presented. This model correlates recovery with: the heat injected, axial pressure loss, percent of slot area in the well, the grain size of the oil sands used, the initial rate of recovery, and the type of additives used with steam. The relative importance of each of these parameters on bitumen recovery is quantified and discussed.

Of special interest in the paper is the presentation of a model of bitumen recovery which involves a radial and an axial driving mechanism. The radial mechanism relates recovery of bitumen to bulk condensation and flashing of the steam. The axial driving mechanism is related to pressure drop encountered by steam and liquids flowing through a long open well or a natural fracture. The relative magnitude and the influence of these two mechanisms on recovery is discussed.

Introduction

Four large Canadian deposits of oil sands are located in the northern half of Alberta: Athabasca, Cold Lake, Peace River and Wabasca; they cover an area larger than 7 million hectares. The Alberta Energy Resources Conservation Board estimates that these deposits contain approximately 215* billion cubic metres of bitumen. From this amount, only 8 billion cubic metres are potentially recoverable by conventional mining techniques from near-surface deposits; the remaining deposits are too deep to be economically mined. New in situ recovery techniques aimed at producing bitumen from deeper formations, at marketable prices, are now under development. Most of these techniques have one major purpose: to introduce heat into the formation in order to reduce the viscosity of bitumen and stimulate its production.

A large scale field experiment which used a pattern of three horizontal wells[1] has been carried out by Texaco Canada Resources in the Athabasca field. The wells in this pattern lie in the lower third of the reservoir and the length of these horizontal sections is approximately 300 m. A number of potential advantages may result from the use of horizontal wells, including improved economics and higher rate of production than from conventional vertical wells.[1,2]

Investigation into the production of bitumen from a horizontal well started in 1979 at the Alberta Research Council, Edmonton. A large physical simulator[3] (Figure 1), was extensively used in the experimental work.

This paper presents major objectives and achievements of this laboratory study.

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*Figure does not indicate carbonate reservoirs.

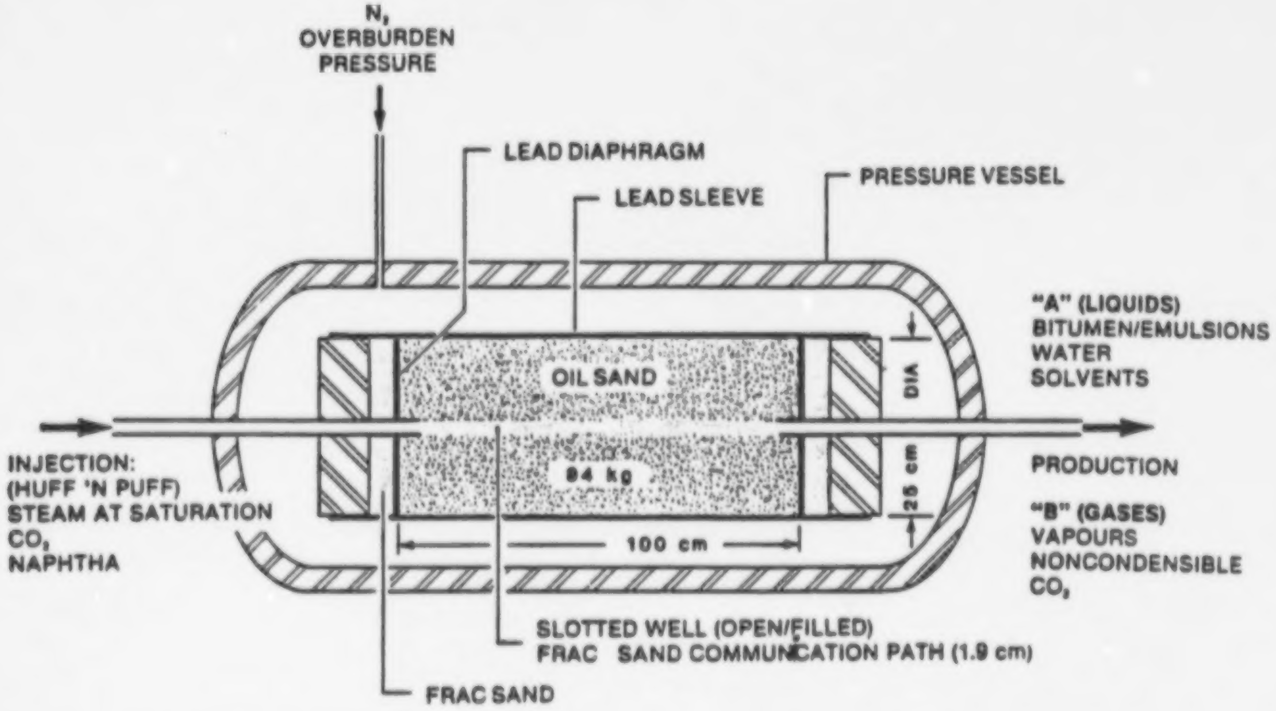
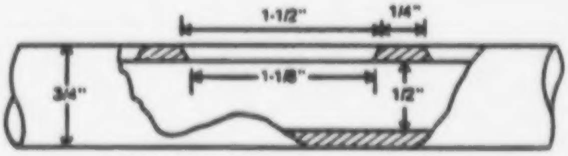


Figure 1 (Detail). Alternate well completion schemes

A. Slotted well (19 mm OD) length/width (mm/mm)	Open area slot %
31/0.51	4.0
31/0.51	0.9
31/0.81	6.0
31/1.27*	9.5
31/1.27**	8.5
B. Screens (25 mm OD) Width (mm)	
1.6	33
0.8	33
C. Frac sand communication path #/OD	
12/19	33

* Filled with frac sand #16
** External sand filter



Slot width: 0.02"

Line lateral area	0.0596 m^2
Line median area	0.06 m^2
Slotted open area	0.002 m^2 (1%)

Slots alternate
4 rows 18 slots (31¼")
4 rows 17 slots (29¼")

Figure 1. Schematic of the physical simulator

Physical simulation

A sizeable portion of a horizontal well in an oil sand formation was partially scaled in the laboratory (Figure 1). The diameter of the horizontal well was considered as being the major geometrical scaling parameter and a field:model scale ratio of approximately 12:1 was selected. At this scale, the oil sand pack (Figure 1a) represents a section of the formation with a radius of approximately 1.5 m containing a horizontal well that is approximately 12 m in length.

Table 1 compares characteristics of the horizontal well as used in the Athabasca project with those of the physical simulator. Some characteristics of the process and the field environment were not scaled but kept as close as possible to the field situation, the most important being the structure of the oil sand[4]. The oil sand, as it is found in a deep or surface mined reservoir, has a well-defined morphology where water, sand and bitumen exist as shown in Figure 2.

Connate water in an oil sand formation is found in a continuous thin film as well as in clusters. The fact that the sand portion of the oil sand is initially water-wet has a significant influence on the success or failure of various recovery processes. Therefore, oil sand from a surface-mined Fort McMurray formation was used and working with an artificially saturated sand, or glass beads, was avoided.

A double-walled pressurized Hassler-type cell was used to simulate overburden pressure on the oil sands. Use of actual oil sand offers the opportunity to study the problems of transport and control of fine sands in an unconsolidated formation. Therefore, the width of the slots and the percentage of open area in the simulator were not scaled, but closely duplicated. Different well completion schemes were tested while the overall size of the oil sands pack was maintained unchanged (see Table 1 and Figure 1.)

Two major groups of runs are characterized by different well completions:
— open wells where different geometrics of slots and different open areas were tested;
— frac sand.

Frac sand of a predetermined size and permeability was axially introduced in a calibrated size hole replacing the slotted well or it was introduced as a filling in a certain slotted well from the beginning of the experiment. Filling a slotted well with frac sand offered the opportunity to observe the combined effect of a limited contact between oil sands and fluids (open area) and of a high specific pressure drop encountered during the axial flow of injected-produced fluids.

Steam stimulation (huff'n'puff) was the recovery process studied in experiments reported in this paper. Steam at, or close to, saturation conditions was injected in cycles (Figure 3), each cycle having an injection and a drawdown stage.

During the injection stage, saturated steam from an external source was injected at approximately 2070 kPa and a constant flow rate. This injection continued

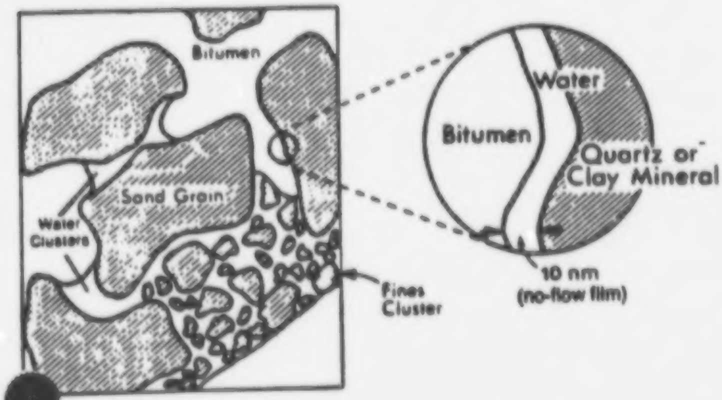


Figure 2. The oil sand structure (courtesy of K. Takamura)

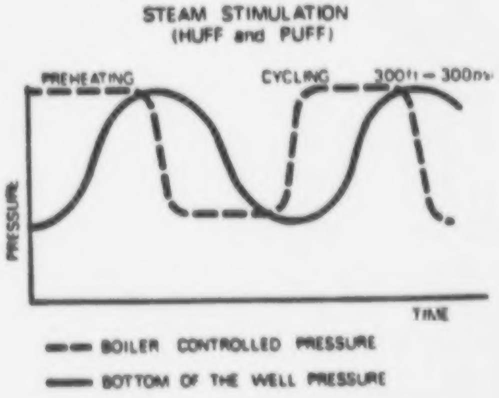


Figure 3. Cyclical steam stimulation (huff'n'puff)

Table 1: Horizontal Well - Field Simulation Versus Laboratory Simulation

#	Type	Characteristics	Field	Laboratory	Units	Observations
1	G	ID	17.2	1.27	cm	
2	E	OD	19.3	1.91	cm	
3	O	Cross area	232.4	1.27	cm^2	
4	M	Total length	304.8	1.00	m	
5	E	Slit width	0.7	0.51/0.81	mm	
6	T	Median diameter	18.3	1.3	cm	(ID + OD)/2
7	R	Median lateral area	175.0	4.08×10^{-2}	m^2	
8	Y	Open area (slotted)	2.1	a. 1.63×10^{-3}	m^2	
				b. 2.61×10^{-3}	m^2	
9		Open area	1.2	a. 4	%	
				b. 6.4	%	from lateral area

Injected fluid: Steam, saturated, (214°C, 2068 kPa), constant mass flow rate

Produced (standard) fluid: condensate, saturated, 2968 kPa

10	F	Injected steam	26,500	10	kg/h	at a normal rate; std. value
11	L	Velocity at inlet	30.4	2.11	m/s	steam
12	O	Velocity at outlet	0.371	2.6×10^{-2}	m/s	condensate
13	W	Re(^{2}) (injection)	1.35×10^{5}	658	--	steam at inlet; stable flow
14		Flow regime	Turbulent	Laminar	--	
15	&	Friction factor	0.06	0.1	--	approximate; smooth pipe
16		Re (production)	0.4	2.1×10^{-3}	--	condensate, D = ID
17	H	Pressure loss (inj.)	1.67	0.18	kPa/m	linear; const. mass flow rate
18	E	Pressure loss (prod)	4.59×10^{-2}	2.25×10^{-3}	kPa/m	pure condensate; const. flow rate
19	A	Average velocity	0.34	a. 1.64×10^{-1}	m/s	even distribution thru lateral area
	T	(slots)		b. 1.03×10^{-1}	m/s	even distribution thru lateral area
20		Total heat injected	7.47×10^{7}	28000	kJ/h	2800 kJ/kg steam
21		Heat load	4.27×10^{5}	6.86×10^{5}	kJ/m^2h	even distribution; avg.lateral area

until the well pressure reaches 2070 kPa. The pressure was then kept constant for 3 minutes using variable injection rates. The rate is controlled by a back pressure valve located on the production end of the horizontal well. The drawdown stage follows and this is controlled by limiting the rate of steam depressurization to a maximum of 100 kPa/min. When the pressure reached 670 kPa, it was maintained for 3 minutes before a new cycle was begun. Fluids produced during the cycle were collected and separated in a high pressure separator in which the temperature was maintained at the temperature measured at the production end of the well.

The liquid phase containing free bitumen and bitumen-in-water emulsions was collected as "Sample A". Any solids produced with fluids were collected in the same sample. Vapors produced during the drawdown were condensed and collected as "Sample B". Sample bottles A and B were changed at the beginning of each cycle. Noncondensibles were sampled for gas chromatograph analysis. The bitumen collected in production fluid "A" was measured for each sample. Data collected during a run was used to produce a set of characteristic curves[3] describing the rate of recovery, rate of production and thermal efficiency.

All measured parameters (pressures, temperatures and flowrates) were separately recorded through a process control computer (MACSYM II), stored on tape and further analyzed using a Tektronix 4052 desk computer.

Approximately 40 thermocouples were evenly distributed in the vertical plane through the median of the pack.

Results

Figure 4 illustrates the characteristic curves obtained for a typical run. Figure 4a shows the recovery curve where the recovery is expressed as the ratio of the recovered bitumen to the original bitumen in place at a given elapsed time.

A characteristic point measured for all recovery curves was the time elapsed to reach 15% recovery. The time to reach 15% recovery was arbitrarily chosen as a parameter representing the early stages of development of the recovery curve.

Figure 4b illustrates the rate of production of a typical simulator run.

Figure 4c is a graph of the thermal efficiency of a typical run. Thermal efficiency is calculated as the net injected heat required to produce a gram of bitumen and is plotted versus net injected heat. The net injected heat resulted from the heat balance of injected and produced fluids. The cumulative total was calculated during the run.

Figure 5 represents a typical thermal profile in a longitudinal cross section which shows the development of temperature both above and below the horizontal well.

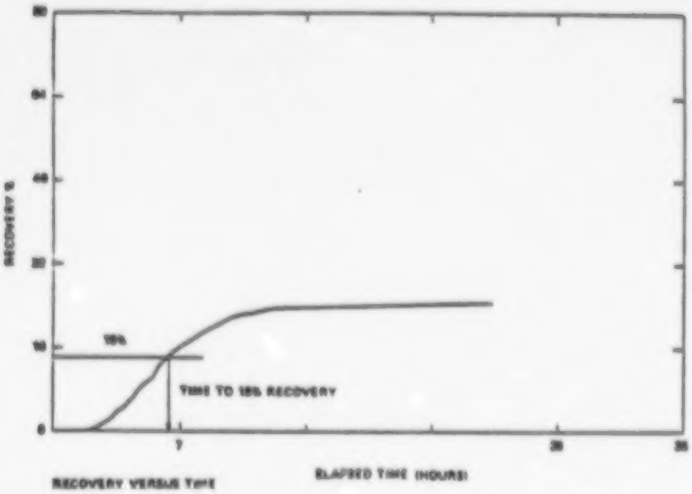
Temperature contours in Figure 5 are represented as a percentage of the injection temperature.

In order to better represent the development of the temperature field, an average value of all thermocouple readings was calculated; this was termed the "bulk temperature" of the pack. Bulk temperatures for the regions above and below the horizontal well were simultaneously calculated. The process is cyclical, so temperatures were recorded only at the peak and valley of the injection cycle.

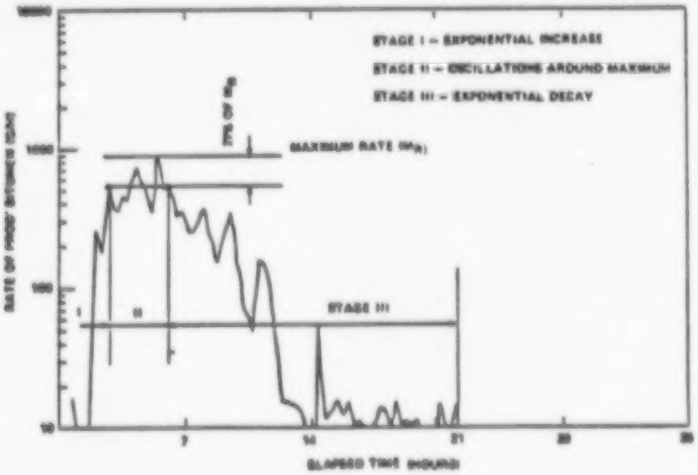
Figure 6 presents a typical development of "bulk temperature" and recovery as a function of run time.

In summary, the following observations were made during 14 runs of a horizontal well simulator[4] and 5 runs of an earlier simulator using frac sand as a communication path.[5]

a. When open wells were used, an initial stage of continuous steam injection of approximately 120 minutes was necessary to trigger the recovery mechanism during the subsequent cyclical injection of steam. During the use of the frac sand communication path, [5,6], production of bitumen was triggered in less than 60 min elapsed time and initial continuous injection was not required. Open wells were identified to "low axial pressure drop process" (0.1 to 0.2 kPa/m) and frac sand wells were identified to "high axial pressure drop" (100 to 1000 kPa/m). Different recovery schemes were required for the "low" and "high" axial pressure wells. It was concluded that diferent recovery mechanisms predominated in "low" and "high" pressure drop schemes.



(a)



(b)

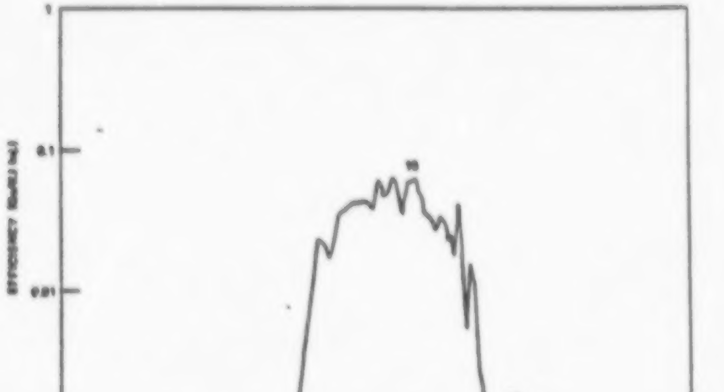


Figure 4. Characteristic curves

(c) EFFICIENCY VS. NET INJ. HEAT

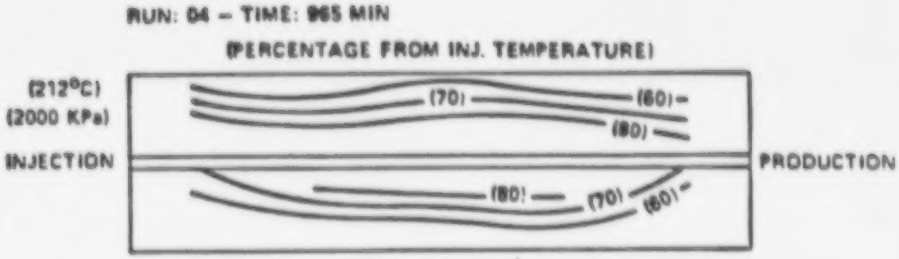


Figure 5. Temperature contours

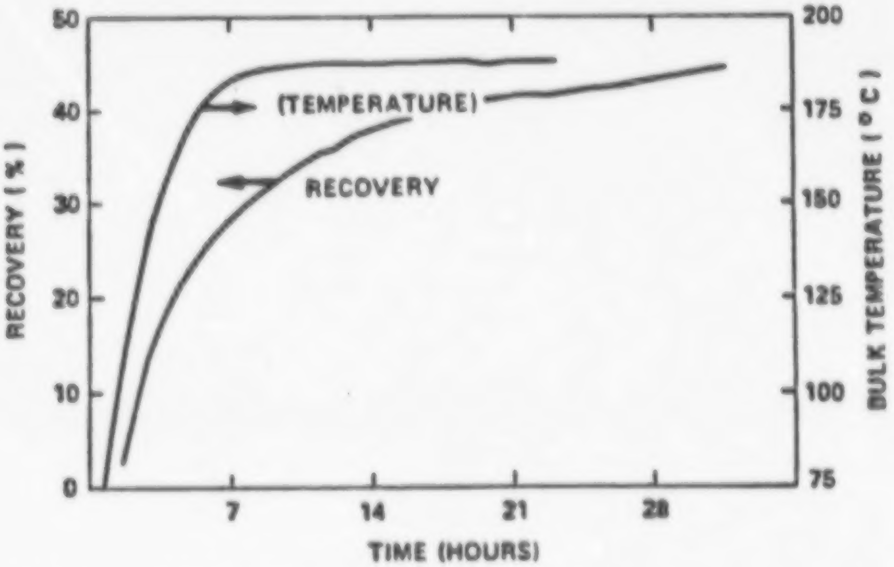


Figure 6. Similarity between temperature and recovery

b. A slightly higher bitumen recovery is observed above the horizontal well than below it, although the shape of the recovery curve both above and below the well were essentially identical. The final distribution of oil saturation was measured using a post-run microcoring technique. The development of recovery above and below the horizontal axis is observed using the record of temperature, which is assumed to follow a similar shape with recovery. The limited role of gravity mechanism during the steam stimulation laboratory experiment was therefore concluded.

c. Significant production of oil began only after the drawdown stage was activated; during the open well experiments, almost all the bitumen is produced during the drawdown stages. This observation indicated the importance of the drawdown stage.

d. The heat transferred through the surface of the horizontal well was in the range of 2 to 3 × 10^5 kJ/m^{2}h, which is ten to one hundred times higher than could be transferred by conduction only. A dissipation and condensation "in bulk" was assumed to justify the value of measured heat flux.

e. Oil sand temperatures around the well oscillate in phase with the pressure of cyclically injected steam. In ''bulk'' condensation-flashing processes were assumed to explain this.

f. Steam was produced when no live steam was injected during the drawdown.

g. The addition of naphtha to a steam process is known to enhance the final recovery.[7] When different well completion schemes were used, contradictory results regarding the effectiveness of naphtha were noticed (Figure 7). The recovery of oil in place, which is graphically presented versus time in figure 7, shows a positive effect of naphtha only where open wells were used. The effect of naphtha is almost unnoticed for frac sand well completion, which is characterized by a medium value of axial pressure drop. For slotted wells filled with frac sand (''high pressure drop''), naphtha had a negative effect on recovery — as shown on Figure 7. From the analysis of run data it was found that as a consequence of the naphtha addition, the specific pressure drop was sensibly reduced, especially in the wells characterized by high pressure drop values.

A physical model of recovery aiming to better explain the complex mechanism of recovery and to offer practical guidelines for field development was formulated.[6]

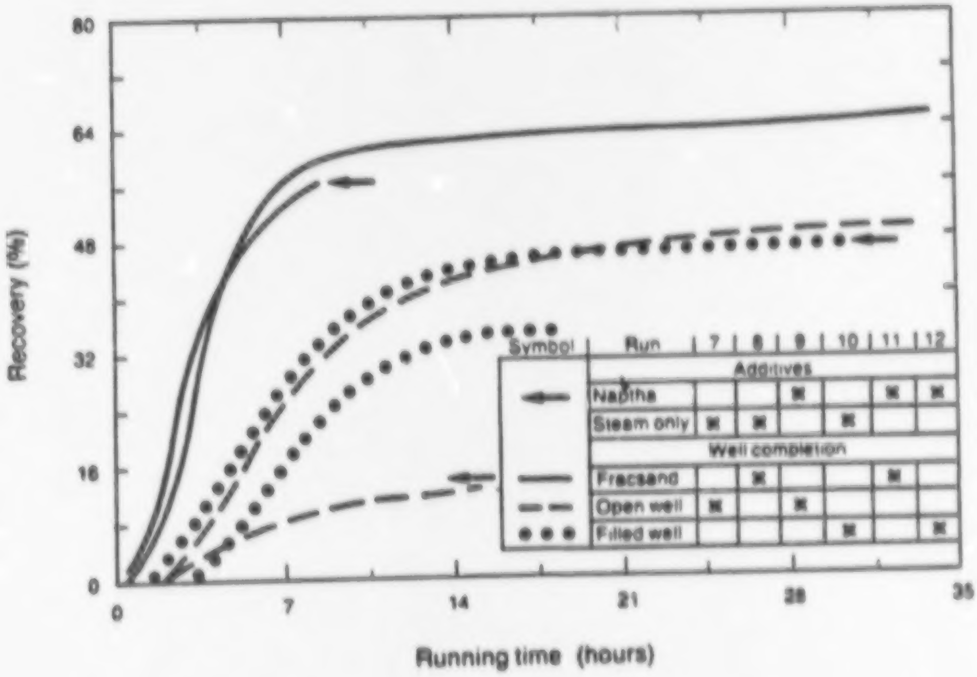


Figure 7. Recovery versus elapsed time (Well completion and additive)

A descriptive model of steam stimulation

Recovery is activated by the injection-drawdown cyclic activity.

The oil sand zone from which recovery occurs is a strong convective zone. During injection, steam penetrates the oil sand and condenses, thereby transferring heat directly to the formation. During the drawdown, oil and/or bitumen emulsion is produced under the action of steam.

Beyond this convective zone, heat is transferred by conduction only; water and oil saturation remain virtually unchanged. The convective zone expands during the process and progressively engulfs the formation previously heated by conduction (Figure 8).

A travelling "transition zone" exists at the interface between the convection and the conduction zones. This transition zone is defined as that conduction volume that will be engulfed by the convection zone during the oncoming drawdown (Figure 8).

During the injection part of the cycle, the pore pressure at any point in the transition zone increases with temperature. The local pore pressure equals the sum of the saturation pressures of both water and bitumen. For temperatures lower than 215°C, the vapor pressure of bitumen is negligible compared to the water vapor pressure.

During the drawdown stage, the pressure in the convection zone decreases rapidly due to the movement of fluids towards the wellbore. This results in flashing of hot water. In the neighboring "transition zone," the rate of decline of temperature and saturation pressure of the formation water are established at a much lower rate than in the convection zone because it is controlled by conduction and not by the convection mechanism. This difference in the rate of decay creates a differential pressure between water-vapor phases contained in the transition and convection zones (Figure 9). As a result of this differential pressure, fluids from transition zones will start moving, and water clustered in the oil sand pores will vaporize, thereby providing the energy for further mobilization of bitumen. The transition zone now becomes a part of the convection zone.

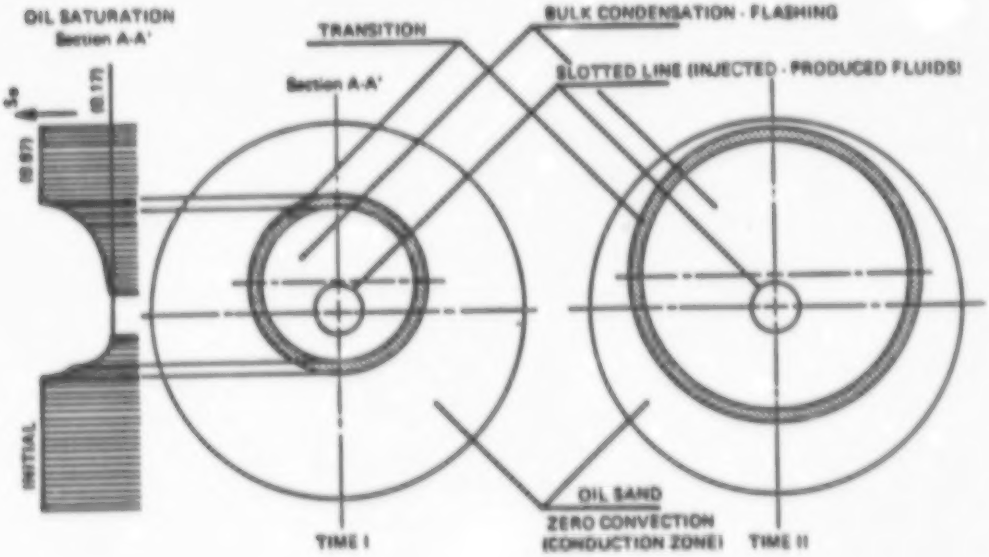


Figure 8. Process zones during steam stimulation

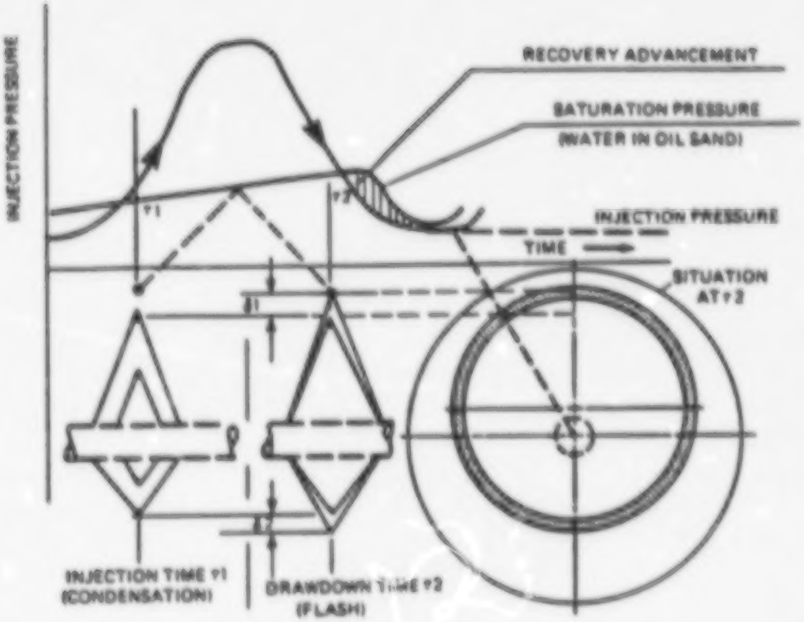


Figure 9. Expansion of convection zone (condensation-flashing)

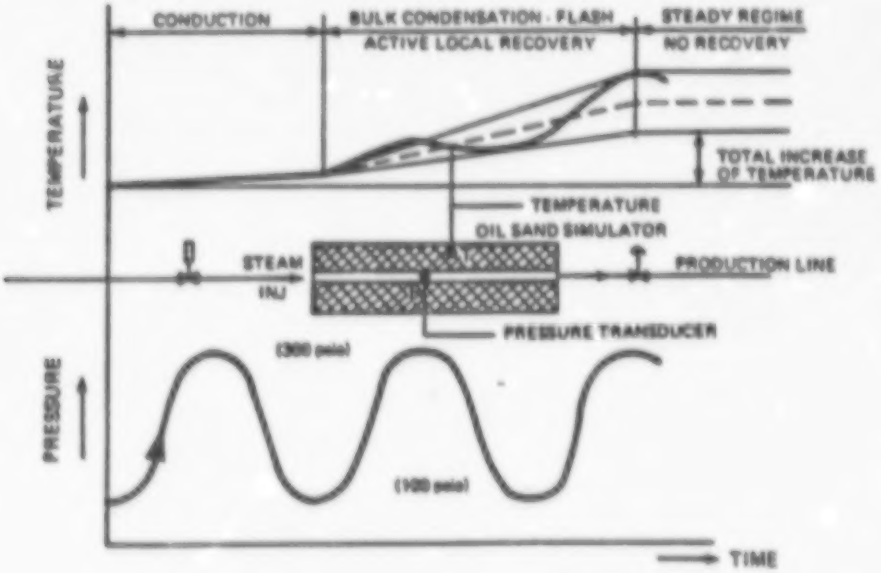


Figure 10. Temperature response to pressure oscillation

In order to initiate the process around the well, steam must be continuously injected. During this period, heat is accumulated by conduction and creates a large transition zone around the well.

During the injection stage, steam can be radially absorbed into the already open network of pores and condensed in bulk. The bulk condensation pressure is lower than the injection pressure in the well. Condensation heat is rapidly released in bulk during this active process, thereby enhancing conditions for in situ emulsification.

Figure 10 schematically shows the local temperature response during a typical run. The continuous increase of temperature is characteristic for conduction, whereas the cyclic temperature response, in phase with injection pressure, is typical for a convection (bulk condensationflashing) mechanism.

The start of a temperature oscillation which is in phase with the pressure oscillation was used to determine the moment at which oil sand is engulfed into the convection zone. Figure 11 is a plot of isochronal lines showing the progression of the convection zone throughout the run. These lines therefore represent the start of local bitumen mobilization.

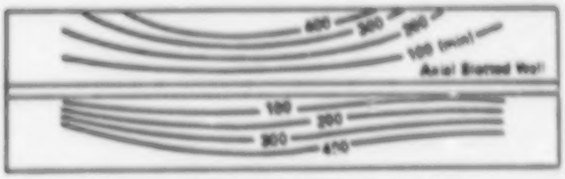


Figure 11. Isochronal lines: moment of engulfing into convection zone (low specific pressure loss)

The direction of radial flow is reversed during cyclic stimulation. An influx of steam takes place during injection and is replaced by an outflux of oil-emulsions-vapors during the drawdown stage.

Gravity contributes to the enhancement of recovery above the well and to the lessening of this effect below the well.

A simple comparison between a flashing-condensation-driving effect and gravity drainage recovery shows that the two mechanisms produce a comparable effect when the maximum gradient in the convection zone averages approximately 0.27°C/m. At lower temperature gradients, the gravitational pumping effect predominates. Therefore, in a field development, gravitational effects will generally be sizeable during the latter stages of the recovery process, when temperature gradients around the well are diminished.

The axial-radial components of recovery

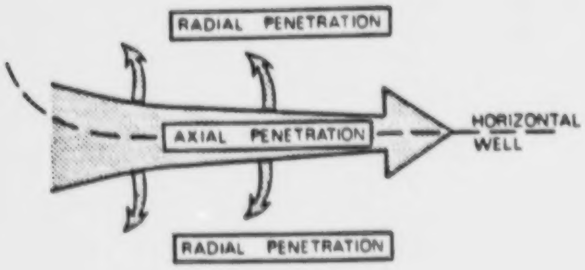
The bulk condensation-flashing mechanisms induced by a cyclical steam stimulation into an oil sand formation is named "radial penetration" (Figure 12a,c).

When a horizontal well is used in steam stimulation, another recovery mechanism occurs together with radial penetration. Steam, under the positive injection pressure, has the tendency to escape the well and penetrate the convection zone and a continuous axial flow pattern along the well is developed (Figure 12b). The effect and magnitude of the "axial penetration" depends on the temperature and characteristics of the formation and the axial pressure drop encountered by steam and liquids flowing through the open well or fracture. The higher the specific pressure drop along the well, the greater the axial penetration of steam into the formation (Figure 12b).

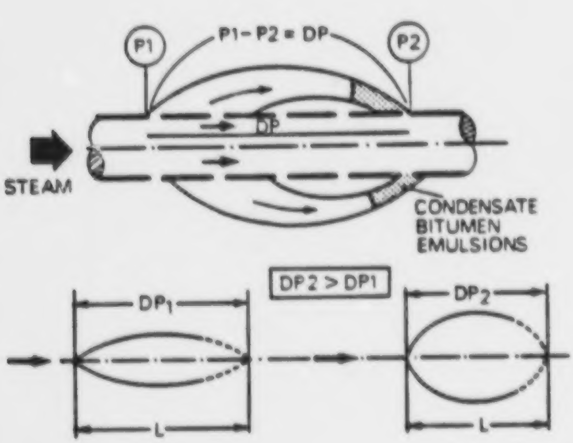
A peak of high pressure drop will travel from the injection towards the production end of the well during recovery. Due to the reduction of the quality of steam along the well, the specific pressure drop will decrease as a function of steam quality (Figure 13a). As temperature around the well increases, the high quality steam will penetrate further along the well (Figure 13b).

Figure 13a shows the variation of specific pressure drop with the steam quality for wells filled with fine and coarse frac sand.

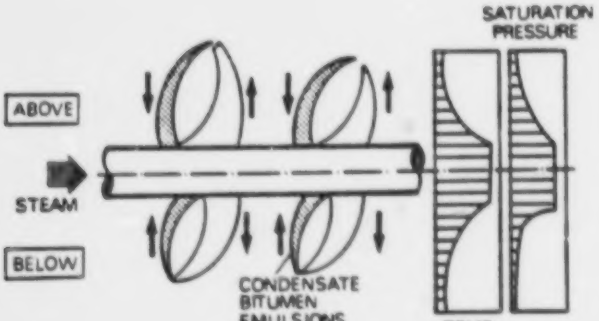
Figure 13a also illustrates the fact that axial penetration could be artificially improved by introducing a porous material (frac sand) into the horizontal well before the production declines.



(a) Schematic



(b) The axial mechanism



(c) The radial mechanism

Figure 12. The axial-radial components of recovery

An uneven development of recovery which progresses from injection toward the production end is observed during a typical run (Figure 14). Figure 14 presents schematically the development of the recovery at different elapsed running times determined experimentally[5]. A linear analogy between temperature development and recovery was used for presenting the development of recovery in Figure 14.

Linear model

In order to determine which were the dominant factors affecting recovery, a linear regression technique was used to model the recovery process. Nine essential parameters were selected[6] and subsequently used in a linear regression to model the data from 14 runs. The parameters (see "X" Table 2) generally fall into one of the following three categories:

a. Well completion (solids produced - sand size -open area).

b. Steam process (heat ratio - total steam injected -specific pressure loss - half recovery time).

c. Additives (naphtha - CO_2).

The heat ratio (HR) equals the ratio of the total heat injected (Q_i) to the net heat transferred to the pack ($Q_i - Q_F$) during steam stimulation:

$$H_R = \frac{Q_i}{Q_i - Q_F} \qquad (1)$$

Where Q_F is the flashing heat withdrawn from the pack during the drawdown stage and is measured using the sammple liquid "B".

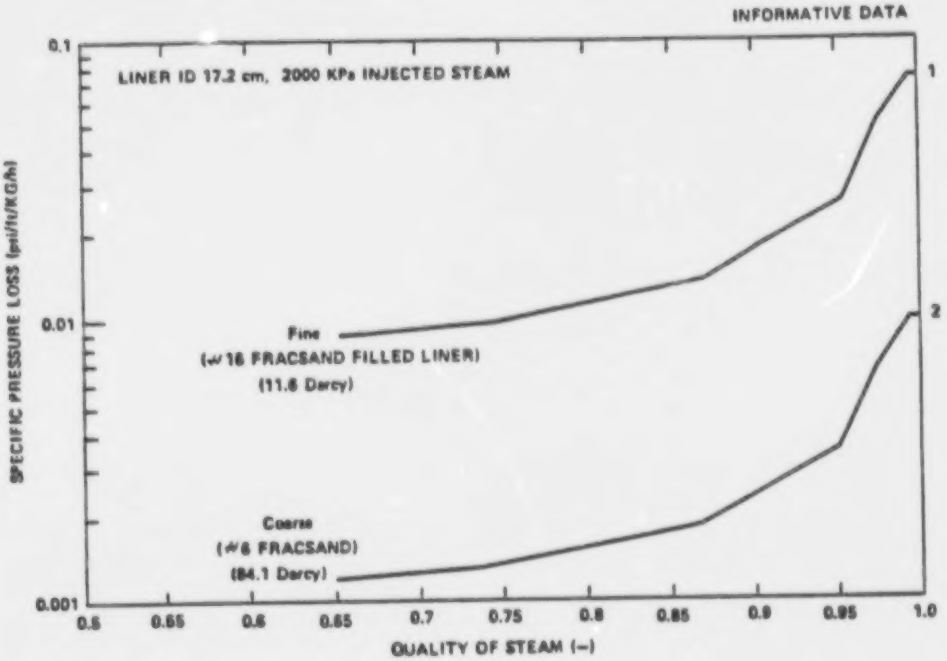
Heat ratio relates directly to radial penetration mechanisms, whereas specific pressure loss relates to axial penetration.

The analytical study of data shows a good correlation of recovery expressed as a linear function on nine normalized parameters (Table 2).

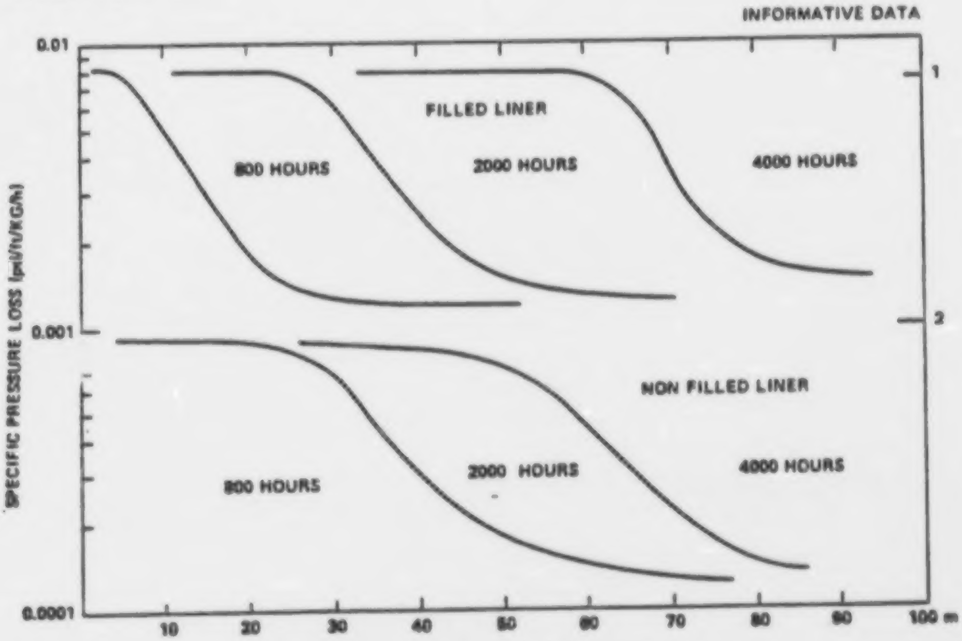
The relative importance of the parameters that define the well completion, the steam process, and the effect of additives can be established using the statistical linear regression applied to previously normalized parameters.

Table 2: Recovery Study - Linear Model - Normalized Values of Parameters and Recovery

No.	Run	Recovery Y	Heat Ratio X1	Naphtha X2	CO_2 X3	Injected Steam X4	Pressure Loss X5	Time @ 15% X6	Produced Solids in Oil X7	Oil Sand Medium Size X8	Open Area of Well X9
1	5	23.600	0.982	1.00E-011	7.14E-012	1.000	3.79E-003	0.474	0.382	0.966	0.121
2	7	34.800	1.000	1.00E-011	7.14E-012	0.587	2.30E-003	0.388	0.836	0.855	0.182
3	8	64.000	0.680	1.00E-001	7.14E-012	0.927	0.115	0.145	3.64E-003	0.947	1.000
4	9	46.100	0.641	1.000	7.14E-012	0.728	2.87E-003	0.276	0.527	0.913	0.182
5	10	47.600	0.518	1.00E-011	7.14E-012	0.590	1.000	0.273	5.45E-005	1.000	0.182
6	11	53.400	0.507	1.000	7.14E-012	0.344	2.53E-002	0.119	1.09E-002	0.884	1.000
7	12	20.700	0.553	1.000	7.14E-012	0.610	0.230	1.000	1.82E-003	0.671	0.182
8	13	34.800	0.708	1.00E-011	1.000	0.593	2.41E-003	0.169	0.818	0.913	0.121
9	14	23.700	0.746	1.00E-011	0.143	0.804	2.30E-003	0.564	1.000	0.855	0.121
10	15	24.700	0.690	1.00E-011	0.143	0.806	4.02E-003	0.366	0.003	0.850	0.121
11	16	36.900	0.670	0.700	0.143	0.842	4.60E-003	0.193	0.667	0.850	0.121
12	17	28.000	0.650	1.00E-011	7.14E-012	0.776	2.87E-003	0.251	0.252	0.850	0.303
13	20	29.500	0.775	1.00E-011	7.14E-012	1.025	2.87E-003	0.740	1.80E-002	1.645	0.982
14	23	19.200	0.810	0.100	7.14E-012	0.850	2.30E-003	0.770	1.390	0.720	2.60E-002
Normalizing			(-)	(%)	(%)	(kg)	$\frac{kPa/m}{kg/h}$	(min)	(%)	(um)	(%)
Values			2.840	10.0	14.0	141.40	600	1068	55.0	200.0	33.0

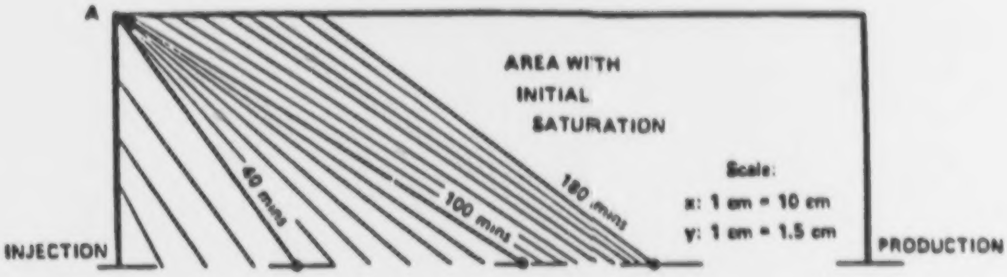


(a) Function of the quality of steam



(b) Function of time

Figure 13. Specific pressure drop



(all data from Run 8)
(high specific pressure loss)

Figure 14. Development of recovery along a horizontal well

Table 3 summarizes the coefficients of linear models represented by equation:

$$Y(\text{Recovery}) = a_0 + \sum_{1}^{9} a_i X_i \qquad (2)$$

where X_i are the normalized values of parameters. The sensitivity of each parameter to recovery is presented in percentage and offers a rapid evaluation of the parameters which are dominant in the process.

The nine parameter linear model was applied to four different groups of runs (A to D) and the variations of the coefficients and of their sensitivity was separately calculated for each group. Table 3 shows the evolution of sensitivity calculated during the progress of the experimental study.

Grouping of normalized parameters is illustrated in Figure 15a,b which uses "half recovery time" and "open area" for exemplification. Figure 16 presents calculated recovery (model "C") versus experimentally determined recovery.

In the well completion group of parameters, the open area is the most important parameter contributing approximately 18% to the process (Table 3 and Figure 14a). In the steam process group of parameters, the axial pressure loss contributes approximately 18%, and heat ratio contribution is approximately 15%. This expresses the relative importance of axial and radial penetration mechanisms. The negative value of approximately 15% for "time at 15%" indicates that the faster the recovery in the early stages of the run, the better the expected final recovery.

The relatively low contribution of CO_2 and naphtha to recovery should be noted.

This is in sharp contrast to the work earlier reported by Redford[7] and may be characteristic of the different physical models used. In the physical model used in this study, with a relatively high ratio of length to diameter, axial flow properties dominate, particularly during the early stages of the run, and naphtha and CO_2 are not anticipated to have major effects. Later in the run recovery limits out on the cell walls. This contrasts with the simulator used by Redford where flow paths were relatively short compared to radial distance and additive and gravitation effects were reported to be much greater.

Conclusions

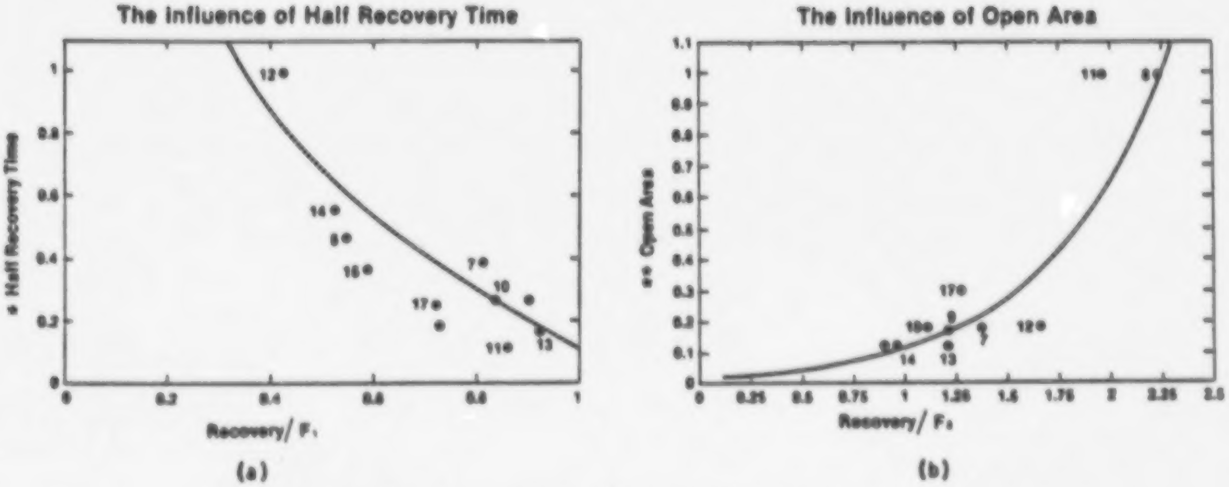
The axial and radial components of recovery can explain the development of the process during in situ steam stimulation in a horizontal well.

The statistical study of recovery showed a good ability to predict the recovery performances of new runs performed in the same simulator but with different well completions or production schemes. The study of relative sensitivity of nine parameters used in the linear regression offers qualitative information for the field operations of horizontal wells. Of major importance to recovery are the pressure drop, heat ratio, open area of the well and time at 15% recovery. Increasing the axial pressure drop, especially for open wells, can increase the performance of horizontal wells. The significance of heat ratio for the

Table 3: Coefficients of Linear Regression and Sensitivity - Calculated for Four Groups of Runs

Parameter	Normalized Absolute Value	ID	Model A (9 runs) Runs #5-14 Coefficient a_i^*	Model A Sensitivity %	Model B (12 runs) Runs #5-17 Coefficient a_i^*	Model B Sensitivity %	Model C (13 runs Runs #5-20 Coefficient a_i^*	Model C Sensitivity %	Model D (14 runs) Runs #5-23 Coefficient a_i^*	Model D Sensitivity %
Heat Ratio	2.840 (-)	X1	10.50	7.0	30.93	14.3	31.61	14.2	31.65	15.4
Naphtha	10.00 (%)	X2	14.43	9.5	17.07	7.9	17.14	7.7	16.38	8.0
CO_2	14.00 (%)	X3	-	-	8.00	3.7	8.08	3.6	8.32	4.0
Injected Steam	141.40 (kg)	X4	20.87	13.8	21.84	10.1	22.12	10.0	19.94	9.7
Pressure Loss	600 . $\frac{kPa/m}{kg/h}$	X5	30.59	20.2	41.28	19.1	41.80	18.8	37.82	18.4
Time @ 15%	1068. (min)	X6	(-)30.40	(-)20.0	(-)28.27	(-)13.0	(-)28.97	(-)13.0	(-)31.56	(-)15.3
Produced Solids	55.0 (%)	X7	13.85	9.0	13.26	6.1	13.27	6.0	8.25	4.0
Grain Size	200.0 (μm)	X8	-	-	(-)17.15	(-)7.9	(-)19.80	(-)8.9	(-)16.72	(-)8.1
Open Area	33.0 (%)	X9	13.14	20.5	39.30	18.1	39.34	17.7	35.08	17.0
Total			151.68	100.0	217.10	100.0	222.13	100.0	205.72	100.0
Free Coefficient* (a_0)			2.824		-4.39		-2.81		1.64	
Correlation Factor (r^2)			0.934		0.934		0.936		0.936	

*Y (Recovery) = $a_0 + \sum_{1}^{9} a_i x_i$



$F_1 = 2.82 + 10.60X_1 + 14.43X_2 + 20.87X_4 + 30.59X_5 + 13.65X_7 + 13.14X_9$

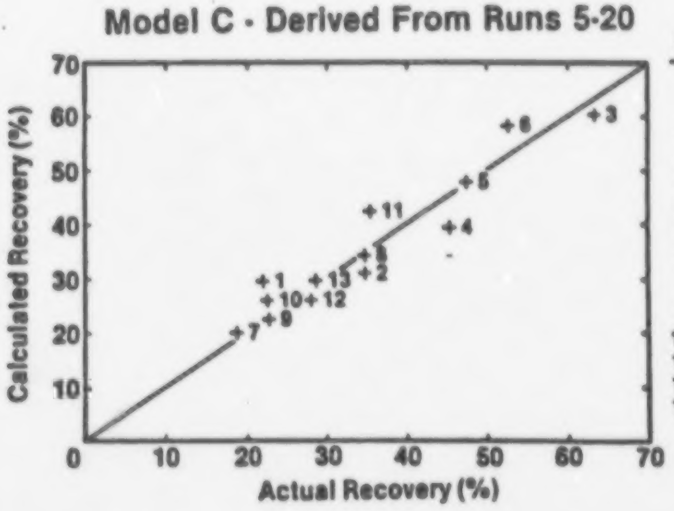
$F_2 = 2.82 + 10.60X_1 + 14.43X_2 + 20.87X_4 + 30.59X_5 - 30.40X_6 + 13.65X_7$

$* \text{ HRT} = \frac{\text{(HRT) Measured (min)}}{\text{1068 (min)}}$ $** \text{ OA} = \frac{\text{(OA) Designed (\%)}}{\text{33 (\%)}}$

RUNS 4 TO 14 WERE USED FOR THE MODEL - X_3 and X_8 INTENTIONALLY OMITTED

(VALUES FOR X SHOWN IN TABLE 2)

Figure 15. Contribution of the half recovery time (a) and open area (b) to final recovery



ID	Run #
1:	5
2:	7
3:	8
4:	9
5:	10
6:	11
7:	12
8:	13
9:	14
10:	15
11:	16
12:	17
13:	20

Figure 16. Calculated versus measured recovery-grouping of date

recovery indicates that flashing is a major driving mechanism. Avoiding condensate segregation at the bottom of the well will help to obtain a symmetrical distribution of flashing processes around the well, in the bulk of the oil sands.

The open area is indicated to be an important parameter of the well completion. Maintaining its initial value during the process by using an appropriate solids control system is another requirement of the design resulting from the model. The significance of "time to 15% recovery" in the linear model indicates that special attention should be dedicated to apply optimum recovery schemes during the initial stage of recovery. A suitable initialization period, and use of CO_2 and solvents or other additives from the beginning of the process are key operational factors reducing the "time to 15% recovery."

Acknowledgements

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Alberta OIL SANDS

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Paper 1

66

LABORATORY STUDIES OF THE STEAM-ASSISTED GRAVITY DRAINAGE PROCESS

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"Advances in Petroleum Recovery & Upgrading
Technology" Conference

June 14 & 15, 1984
Calgary, Alberta, Canada

INTRODUCTION

In 1978 Esso Resources drilled a horizontal well (1) at the Cold Lake Leming pilot to field test the steam-assisted gravity drainage process. Design and initial operation were based on early theoretical and laboratory work. Over the years, testing of the pilot through a number of operational phases has been guided by continued development of theory and scaled physical model studies.

Steam-assisted gravity drainage is a process for recovering heavy oil by continuously injecting steam into a growing steam chamber formed above a horizontal production well. Steam is injected into the steam chamber at the rate required to maintain the pressure within the chamber. The steam flows to the edge of the chamber and condenses. The heated oil and condensed steam drain along the walls of the chamber by gravity to the production well below (Figure 1).

In the first theoretical paper on this topic (2), equations were developed to predict the rate of oil drainage to a horizontal well. The equations assumed steam injection in a vertical plane above the horizontal well and an infinite reservoir.

The second paper (3) extended the theory to the practical arrangement of finite reservoir width (confined well spacing). Subsequent papers have extended the theoretical equations to reflect the initial vertical steam chamber growth period caused by steam injection from a horizontal well situated just above the horizontal production well (4), and have refined the definition of the exponent 'm' used in the equations (5).

This paper extends the theory to examine steam injection from a vertical well situated above the horizontal production well and presents laboratory results in support of the theory.

THEORY

The theoretical equation derived (2) to predict the rate of drainage from both sides of a horizontal well to a unit length of horizontal well located at the base of a reservoir of infinite width is

$$Q = 2\left(\frac{2kg\alpha\phi\Delta S H}{m\nu_s}\right)^{1/2} \qquad E1$$

when it is assumed that initial steam injection is from a vertical plane above the horizontal well.

The horizontal velocity of the steam chamber interface is

$$\left(\frac{\partial x}{\partial t}\right)_y = -\left(\frac{\partial y}{\partial t}\right)_x \Big/ \left(\frac{\partial y}{\partial x}\right)_t \qquad E2$$

Since the interface is advancing, the rate of oil flowing into a unit area of interface is less than the rate of oil flowing out. Thus, the change in oil rate across the section is related to the interface movement by

$$\frac{\partial Q}{\partial x} = \phi\Delta S\left(\frac{\partial y}{\partial t}\right) \qquad E3$$

Combining equations E2 and E3 with a differential form of equation E1 ($\partial Q/\partial y$) produces an equation containing the horizontal steam chamber interface position, x

$$\frac{x}{t} = \left(\frac{\partial x}{\partial t}\right)_y = \frac{1}{\phi\Delta S}\left(\frac{\partial Q}{\partial y}\right) = \left(\frac{kg\alpha}{2\phi\Delta S m\nu_s(H-y)}\right)^{1/2} \qquad E4$$

Similarly, the vertical steam chamber position, y, is

$$y = H - \frac{kg\alpha}{2\phi\Delta S m\nu_s}\left(\frac{t}{x}\right)^2 \qquad E5$$

The combination of equations E4 and E5 allow the construction of steam chamber interface contours shown in Figure 2. The theoretical movement of the interface curves away from the horizontal production well implies that negligible gravity head is required for fluid flow to the horizontal well. In practice, the interface will remain connected to the horizontal well (Figure 3) and the constant '2' in equation E1 is changed to '1.5' (TANDRAIN approximation) (3).

Equation E6 was developed (3) to predict oil production rate from a reservoir of finite width.

$$Q^* \sqrt{3/2} - T^{*2}\sqrt{2/3} \qquad \text{E6}$$

$$\text{with } T^* = \frac{t}{W}\left(\frac{kg\alpha}{\phi\Delta S\,\nu_s\,mH}\right)^{1/2}$$

$$Q^* = 2Q\left(\frac{m\nu_s}{kg\alpha H\phi\Delta S}\right)^{1/2}$$

If steam injection is from a horizontal well situated just above the horizontal production well, then the steam chamber initially grows to the top of the reservoir. The oil production rate during the initial vertical growth phase (4) is

$$Q = 2.81\left(\frac{kg\alpha}{m\nu_s}\right)^{2/3}(\phi\Delta St)^{1/3} \qquad \text{E7}$$

and the vertical growth rate is

$$h = 1.31\left(\frac{kg\alpha}{\phi\Delta S\,\nu_s\,m}\right)^{1/3} t^{\,2/3} \qquad \text{E8}$$

The total oil production rate for this dual horizontal well layout in a reservoir of finite width is a combination of equations E7 and E6 as shown in Figure 4.

Horizontal Well Use

A practical system consists of steam injection from a fully perforated well (vertical well) above the horizontal production well. In this situation, the steam chamber contours perpendicular to the horizontal and vertical wells would be comparable to Figure 3. The contours would be expected to grow along the horizontal well in a manner comparable to Figure 2.

If we assume a simple production system with one vertical injection well above a horizontal production well then the total oil rate in an infinite reservoir is given by

$$Q_T = 2\,(L_D + L_U)\left(\frac{1.5kg\alpha\phi\Delta SH}{m\nu_s}\right)^{1/2} \qquad \text{E9}$$

The length of well being used in the downhole direction, (towards the end of the horizontal well) L_D, is obtained from the initial length, L_{DI}, and equation E6,

$$L_D = L_{DI} + t\left(\frac{kg\alpha}{2\phi\Delta Sm\nu_s H}\right)^{1/2} \qquad \text{E10}$$

The steam chamber contours in the downhole direction are comparable to Figure 2.

In the uphole direction, hot fluids in the horizontal well conduct heat to the reservoir in advance of the steam chamber and raise the reservoir temperature. A reservoir temperature increase will change the steam chamber interface by varying the value of 'm' according to (4),

$$m = \left[\nu_s \int_{T_R}^{T_S} \left(\left(\frac{1}{\nu} - \frac{1}{\nu_R}\right)/(T-T_R)\right) dT\right]^{-1} \qquad \text{E11}$$

The hot horizontal production well produces variations in T_R and 'm' as a function of production temperature, time and reservoir location. Thus, the interface contours become distorted.

Adjacent to the hot horizontal well the reservoir temperature may be assumed to be equal to the production temperature, thereby

$$m' = [\nu_s \int_{T_P}^{T_S} ((\frac{1}{\nu} - \frac{1}{\nu_R})/(T-T_R)dT]^{-1} \qquad E12$$

The length of well being used in the upwhole direction is therefore,

$$L_U = L_{UI} + t \left(\frac{kg\alpha}{2\phi\Delta S_o m' \nu_s H}\right)^{1/2} \qquad E13$$

The total oil drainage rate is obtained from equations E9, E10 and E13. If m'= m (hot fluids throughout the horizontal well) and the initial horizontal well use is zero, then combining E9, E10 and E13 produces the simple drainage rate relationship,

$$Q_T = \frac{3.46\ kg\alpha t}{m' \nu_s} \qquad E14$$

By equation E14 the oil rate is independent of reservoir height, porosity and oil saturation reduction. However, this equation assumes a reservoir of infinite dimensions, an infinite horizontal well and no oil production from steam chamber ends.

A similar equation can be obtained for reservoirs of finite width by combining the basic equation for oil production in a finite reservoir, E6, with the well growth equations E10 and E13. The resulting equation, E15, again assumes an infinite horizontal well and no production from steam chamber ends.

$$Q_T = 3.46\,\frac{kg\alpha t}{m' \nu_s} - 2.33\,\frac{t^3}{W\phi\Delta S}\left(\frac{kg\alpha}{Hm' \nu_s}\right)^2 \qquad E15$$

EXPERIMENTAL DESCRIPTION

Two types of experimental techniques are used to investigate the steam-assisted gravity drainage process: 1) atmospheric pressure, two dimensional, visual models, and 2) three dimensional high pressure models.

Visual models, shown in Figure 5, are glass-sided with a wooden frame and typically 30 cm wide by 20 cm high by 2.5 cm thick. They are filled with sand and saturated with Cold Lake crude. Atmospheric pressure steam is injected into the upper horizontal well and produced fluids are collected from the lower well. The upper horizontal well can be replaced by a vertical steam injection well if required. The wells are 0.5 - 1 cm diameter slotted copper tubing. Figure 6 shows the layout of a visual model used to investigate the growth of the chamber along the horizontal well; production can be from either end.

A schematic of the high pressure model apparatus is shown in Figure 7. The reservoir model is constructed from 13 mm steel and is 36 cm in diameter and 39 cm high. The horizontal production well and vertical injection well are 0.5 cm diameter slotted tubing with a 200 mesh protective stainless steel screen. The model operates at 1.4 - 2.7 MPa. The reservoir is created with sand and water; the water is subsequently displaced by Cold Lake crude.

Both types of model can be scaled to field conditions by selecting reservoir dimensions and sand permeability such that the scaling constants, B_3 and T_D, derived by Butler et al (2) are the same for model and field.

RESULTS AND DISCUSSIONS

Visual Models

A: Oil Rate

Figure 8 shows the good agreement between theoretical and experimental oil production rates in a visual model. The theoretical rate is obtained from equations 26 and 27 and on a scaled basis the test time is equivalent to 27 years. A high oil rate peak consistently occurs as the steam chamber reaches the top of the model and quickly changes shape. Typical oil recovery from the steam chamber is 80% in the visual models.

In 2-dimensions (i.e. no growth along the horizontal well), theory accurately predicts the oil production rate by steam-assisted gravity drainage.

B: Steam Chamber Growth

The steam chamber interface curves for a typical test are shown in Figure 9. The horizontal steam chamber growth rates are:

	Experimental	Theoretical
y = 0.25 H	1.9 cm/hr	2.5 cm/hr
y = 0.5 H	3.5 cm/hr	5.0 cm/hr
y = 0.75 H	6.0 cm/hr	7.5 cm/hr
y = H	6.5 cm/hr	-

In general the horizontal growth rates are comparable to theory at the centre of the reservoir. Near the horizontal well, the theoretical growth rates are larger than experimental since theory assumes that the steam chamber interface will not remain attached to the horizontal well (Figure 2). At the top of the reservoir theory predicts that the contours extend to infinity; a large amount of steam override would significantly lower the oil-steam ratio of the process. All the visual model results show very little steam override at the top of the reservoir.

After the initial vertical growth period, experimental evidence indicates that the steam chamber interface can be approximated as a straight line connecting the horizontal well and the reservoir top, and passing through the centre of the reservoir at the point calculated from theory. This approximation produces oil production rates which differ only 5% from theory, and permits a reasonable estimate of overburden heat losses and the areal extent of the steam chamber.

The steam chamber interface curves along a cold horizontal well are shown in Figure 10 and along a hot horizontal well containing produced fluids in Figure 11. Along the cold well the contours are comparable to theory (Figure 2); along the hot well the growth is faster. The exact shape of the contours along the hot well is dependent on T_s, T_p, T_R, t, α and y. The growth rate ratio along the horizontal well, cold: hot is 1:1.5; theoretically the ratio is 1:1.4.

C: Viscosity Variation

Three identical tests were completed using oils with viscosities at steam temperature of 3.8, 7.6 and 14.8 m^2/d (Cold Lake bitumen). Figure 12 shows that the average experimental oil production rate is in excellent agreement with the average theoretical rate over the viscosity range examined.

Similar tests have shown that theory accurately predicts the effect of absolute permeability and reservoir height on oil production rate.

High Pressure Model

A: Steam Chamber Growth

Steam chamber contours from a typical scaled high pressure model test are shown in Figure 13. The shape is generally comparable to that predicted by theory; the growth rates along the horizontal well are within 10% of the theoretically predicted rates. The steam chamber contours indicate that a substantial portion of the produced oil is obtained from steam chamber ends. This end zone volume is not included in the theoretical steam-assisted gravity drainage equations.

B: Oil Rate

Disregarding oil production from the end zones, the theoretical oil production rate for the high pressure model can be calculated from equations B6, B10 and B13. Figure 14 shows that the theoretical rate without end zone production is substantially lower than the experimental oil production rate. Therefore, the oil zone contribution from steam chamber end zones is significant. Oil recovery from steam chamber is 80-85%.

C: Injection Pressure Variation

Use of a high pressure model allows study of the effects of an important process parameter: steam chamber pressure. As injection pressure and steam injection temperature increase, the oil viscosity at steam temperature decreases. From equation B14 as viscosity decreases, oil production rate will increase if other factors remain constant. Similarly, as injection temperature increases, steam chamber temperature increases and more energy is required per unit oil produced; thus, the oil-steam ratio will decline. Figure 15 shows the expected effect of injection pressure on the oil rate and oil-steam ratio observed in the high pressure model.

Analytical Simulation of the High Pressure Model

The theoretical dimensions of the steam chamber can be obtained from equations B4, B10 and B13. If the steam chamber contact with the overburden is comparable to that observed in the visual model, then the interface can be approximated as a straight line connecting the horizontal well and the reservoir top, and passing through the centre of the reservoir at the theoretical point.

Given the variation in steam chamber shape with time from the theoretical equations, the oil recovery (80%) and the other factors which influence heat loss in the system, a model has been developed which predicts the

injection and production rates. An initial comparison between the experimental and simulated oil rates is shown in Figure 16. The simulator is currently being improved and modified.

CONCLUSIONS

Both low pressure visual models and high pressure models produce results that agree well with theory. Low pressure models show that the theory developed by Butler et al, accurately predicts oil production rate and the effect of oil viscosity, reservoir height and absolute permeability. The scaled models indicate that the process has a long life span and that the steam override and subsequent overburden heat loss is not as great as initially indicated.

Theory can be extended to predict steam chamber growth along a horizontal well from a vertical steam injection well. The experimental growth rates are comparable to theory. The effect of injection pressure variation on oil production rate and oil-steam ratio is as expected by theory.

The preliminary version of an analytical steam-assisted gravity drainage simulator agrees well with experimental data. Improvements and modifications will be required to create a useful predictive tool for field application.

NOMENCLATURE

Q = volumetric oil rate per unit length of well ($m^3/d.m$)

Q_T = volumetric oil rate (m^3/d)

Q^* = dimensionless oil rate

k = effective permeability - taken as 40% absolute permeability (m^2)

ΔS = initial oil saturation - final oil saturation

H = reservoir height (m)

L_D = downwell length of horizontal well used (m)

L_{DI} = initial downwell length of horizontal well used (m)

L_U = upwell length of horizontal well used (m)

L_{UI} = initial upwell length of horizontal well used (m)

T = temperature (°C)

T_R = reservoir temperature (°C)

T_S = steam temperature (°C)

T_P = production temperature (°C)

T^* = dimensionless time

W = reservoir width (m)

Q_I, T_I = scaling factors

h = steam chamber height (m)

g = acceleration due to gravity (m/d^2)

m, m' = dimensionless constants

ν_S = oil viscosity at steam temperature (m^2/d)

x, y = steam chamber coordinates

t = time (d)

α = thermal diffusivity (m^2/d)

ϕ = porosity

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STEAM CONDENSES AT CHAMBER INTERFACE
OIL & CONDENSATE DRAIN TO WELL BY GRAVITY
CHAMBER GROWS UP AND OUT

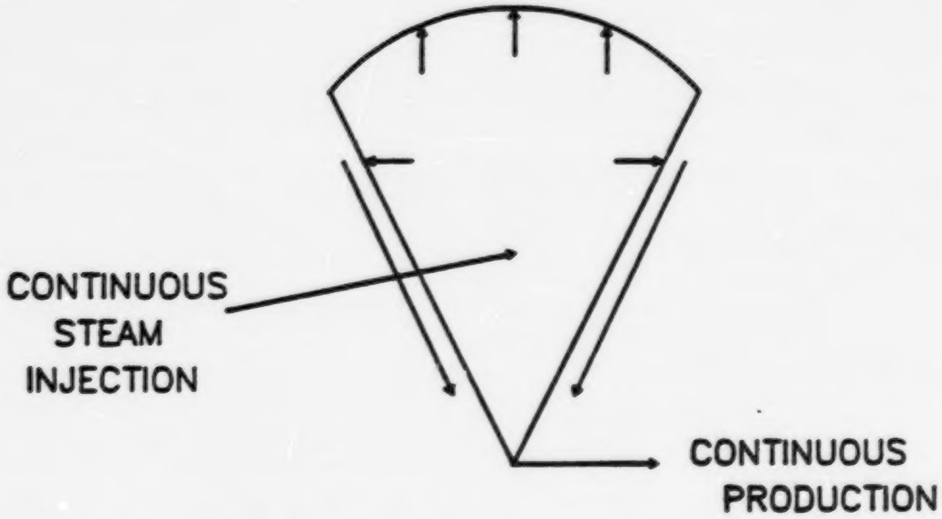

FIGURE 1 – STEAM-ASSISTED GRAVITY DRAINAGE PROCESS

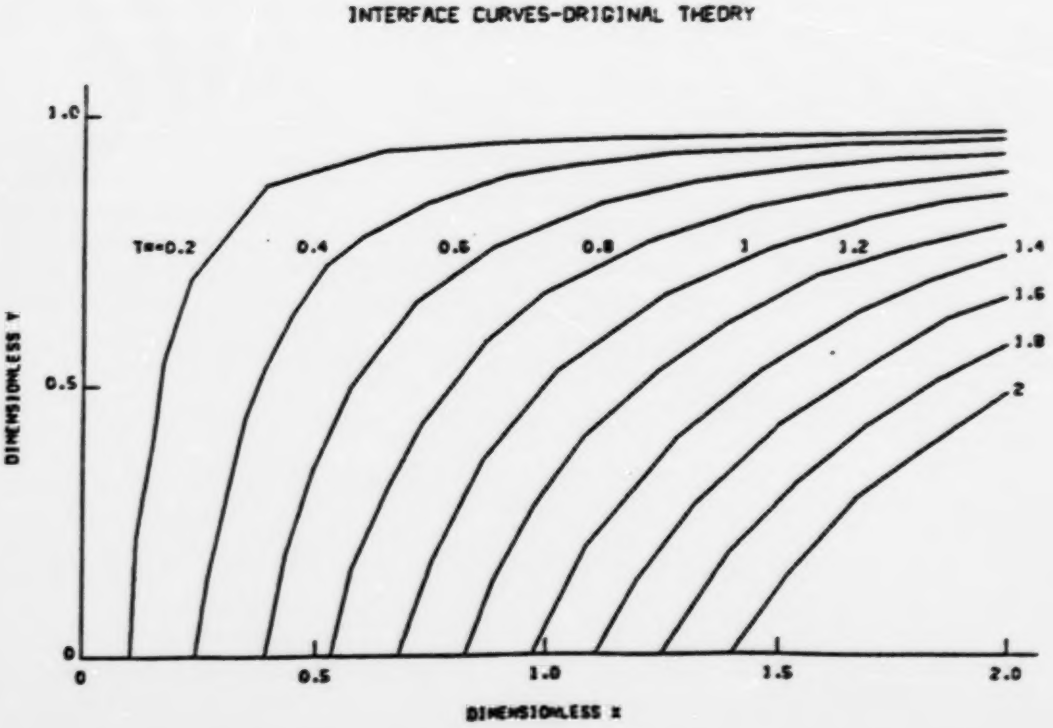

FIGURE 2 – INTERFACE CURVES FROM ORIGINAL THEORY

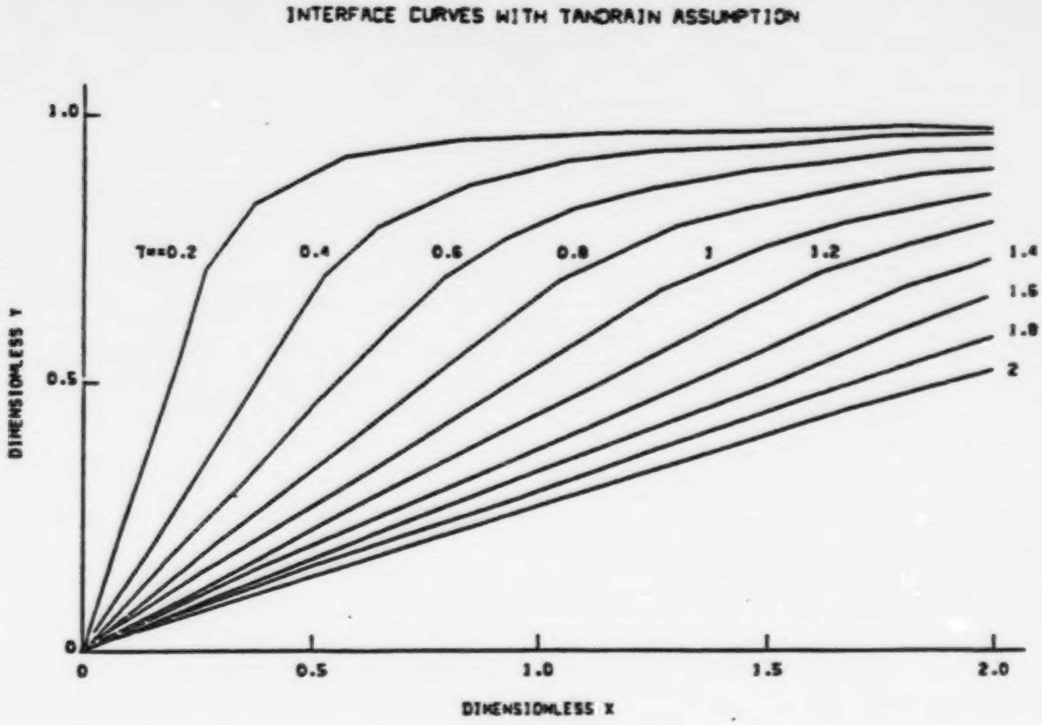

FIGURE 3 – INTERFACE CURVES WITH TANDRAIN

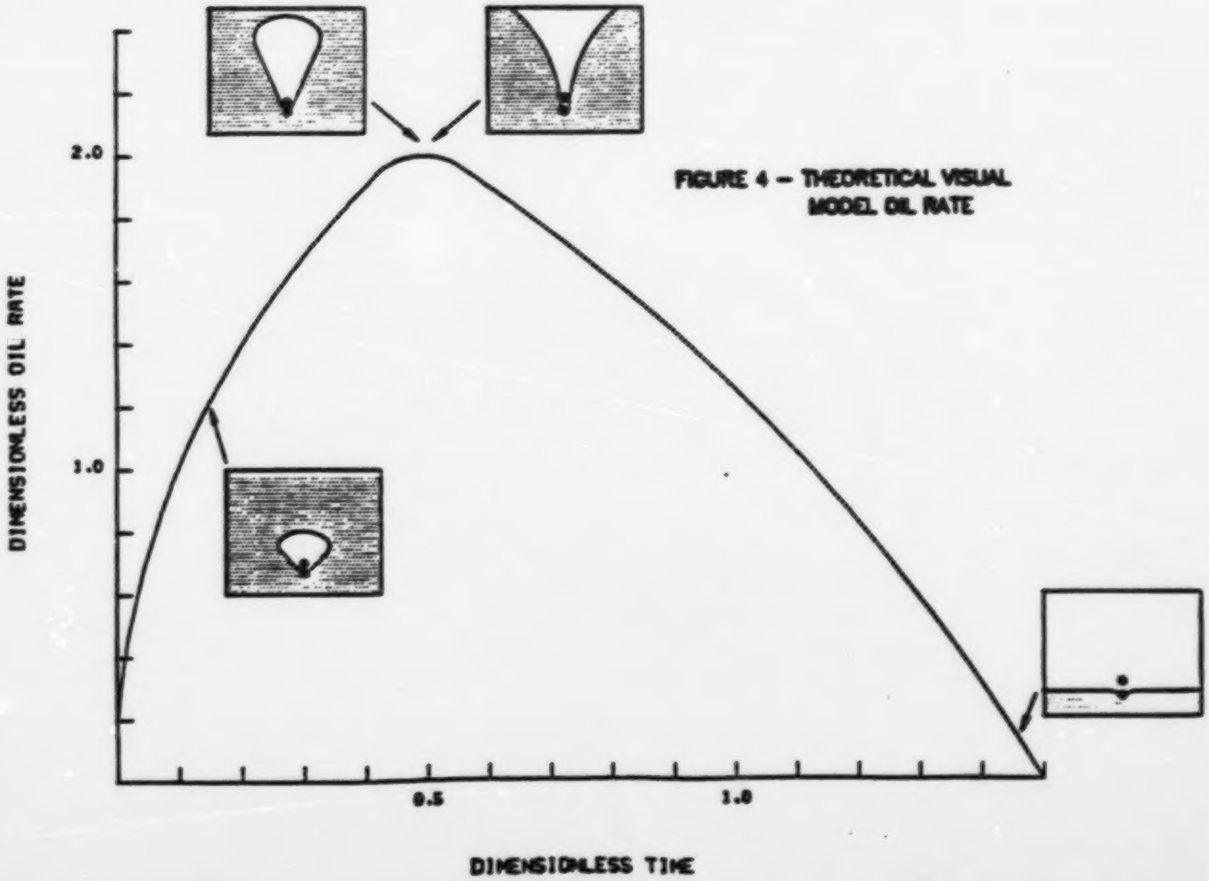

FIGURE 4 – THEORETICAL VISUAL MODEL OIL RATE

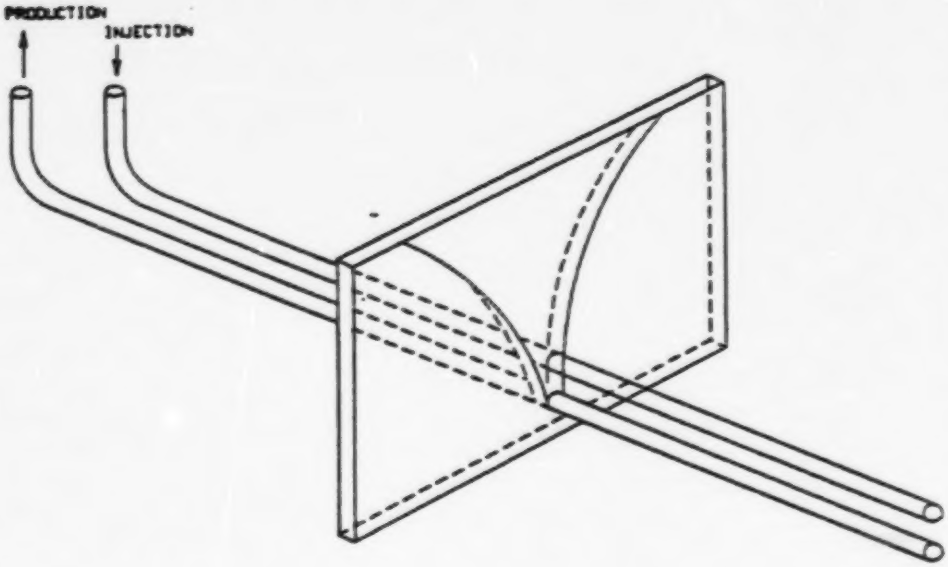

FIGURE 5 – BASIC VISUAL MODEL

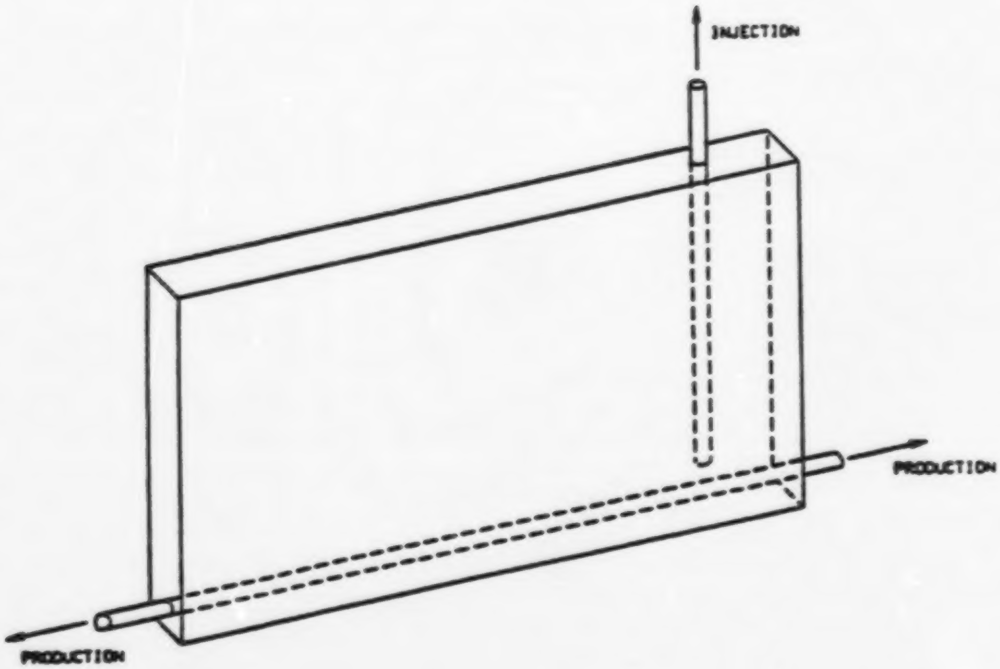

FIGURE 6 – HORIZONTAL WELL VISUAL MODEL

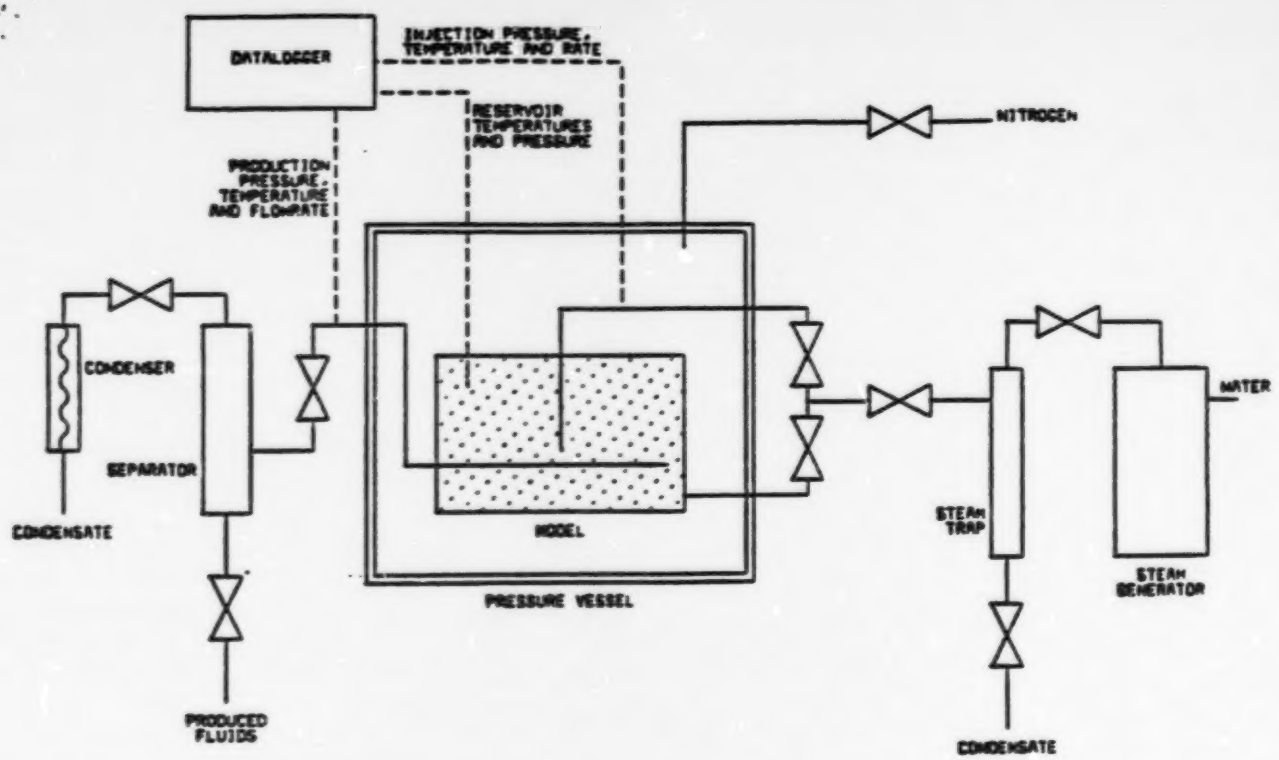

FIGURE 7 – HIGH PRESSURE MODEL SCHEMATIC

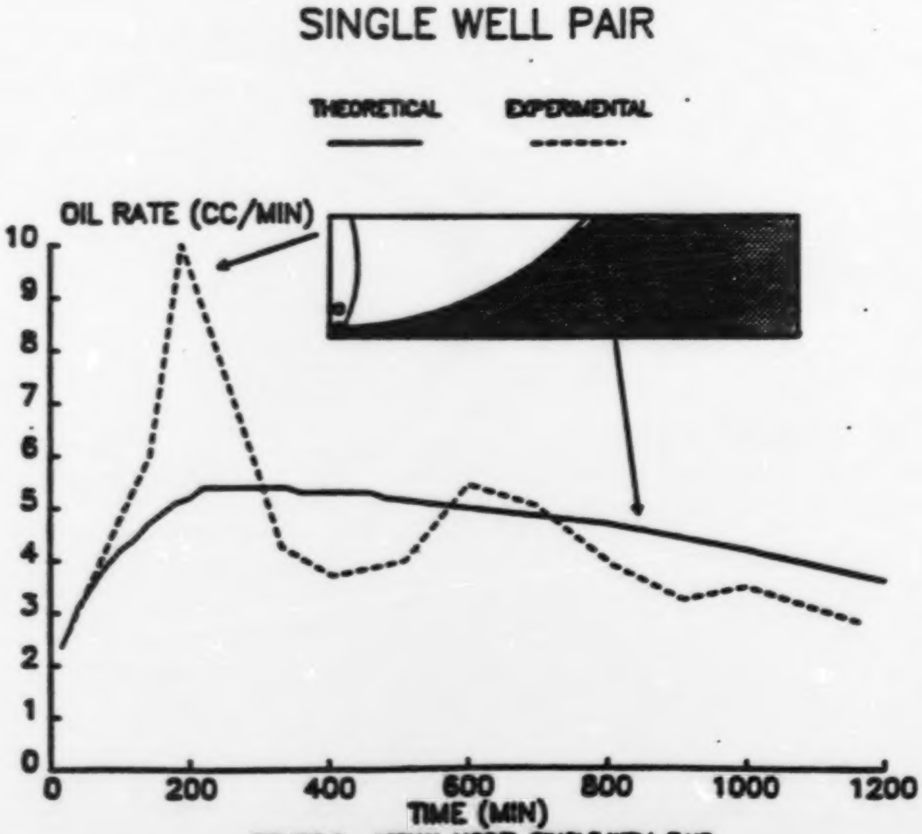

FIGURE 8 – VISUAL MODEL SINGLE WELL PAIR

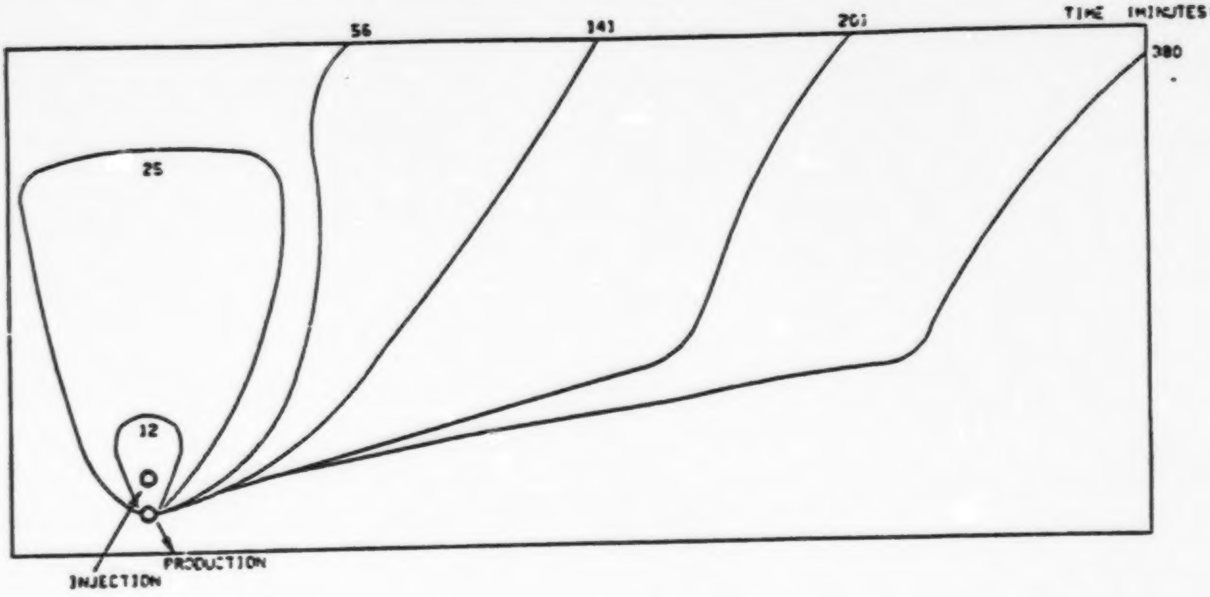

FIGURE 9 – VISUAL MODEL STEAM CHAMBER GROWTH

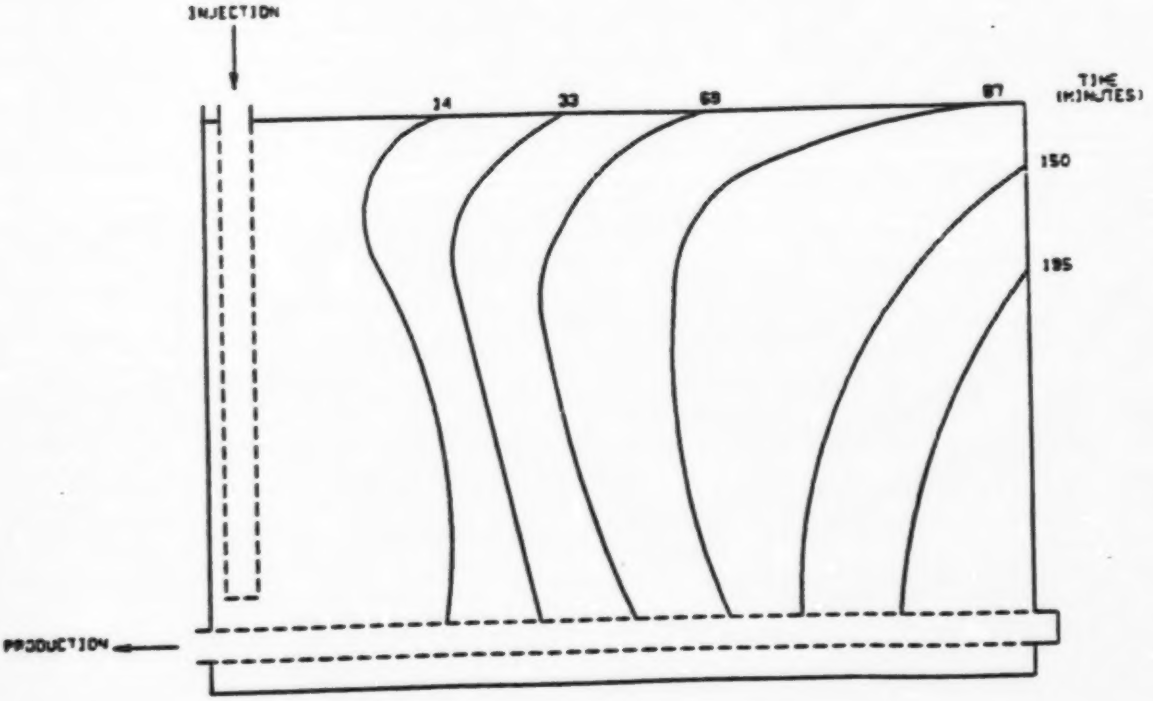

FIGURE 10 – VISUAL MODEL COLD HORIZONTAL WELL STEAM CHAMBER GROWTH

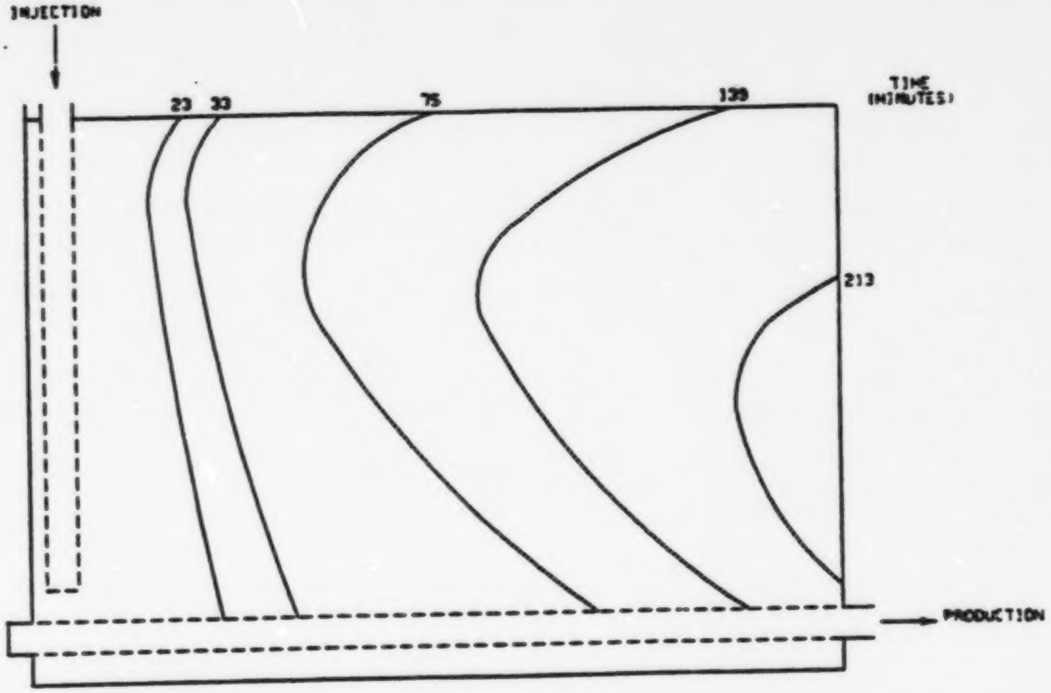

FIGURE 11 — VISUAL MODEL HOT HORIZONTAL WELL STEAM CHAMBER GROWTH

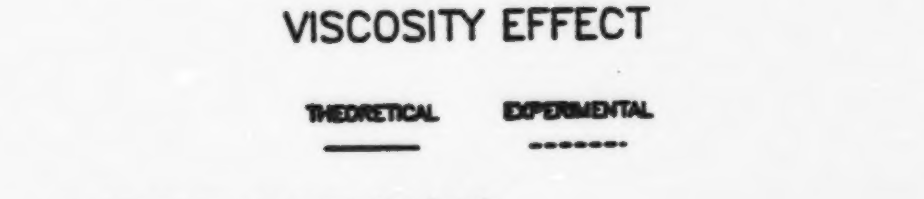

FIGURE 12 — VISUAL MODEL VISCOSITY COMPARISON

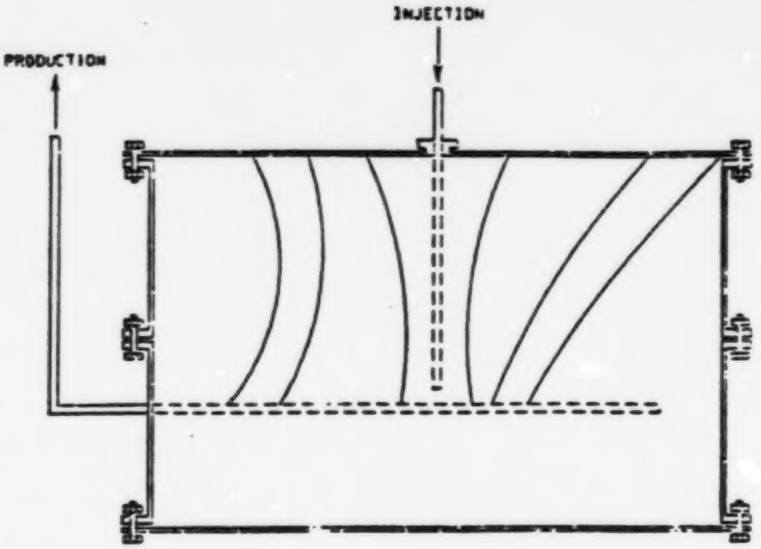

FIGURE 13 – HIGH PRESSURE MODEL STEAM CHAMBER GROWTH

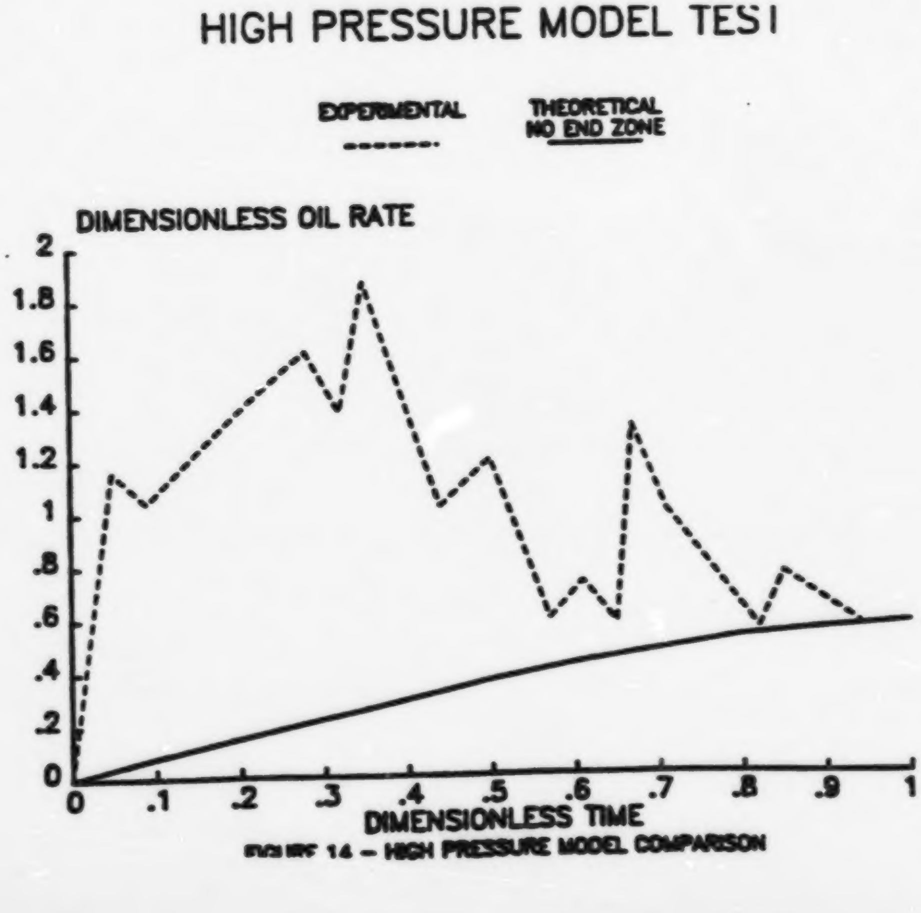

FIGURE 14 – HIGH PRESSURE MODEL COMPARISON

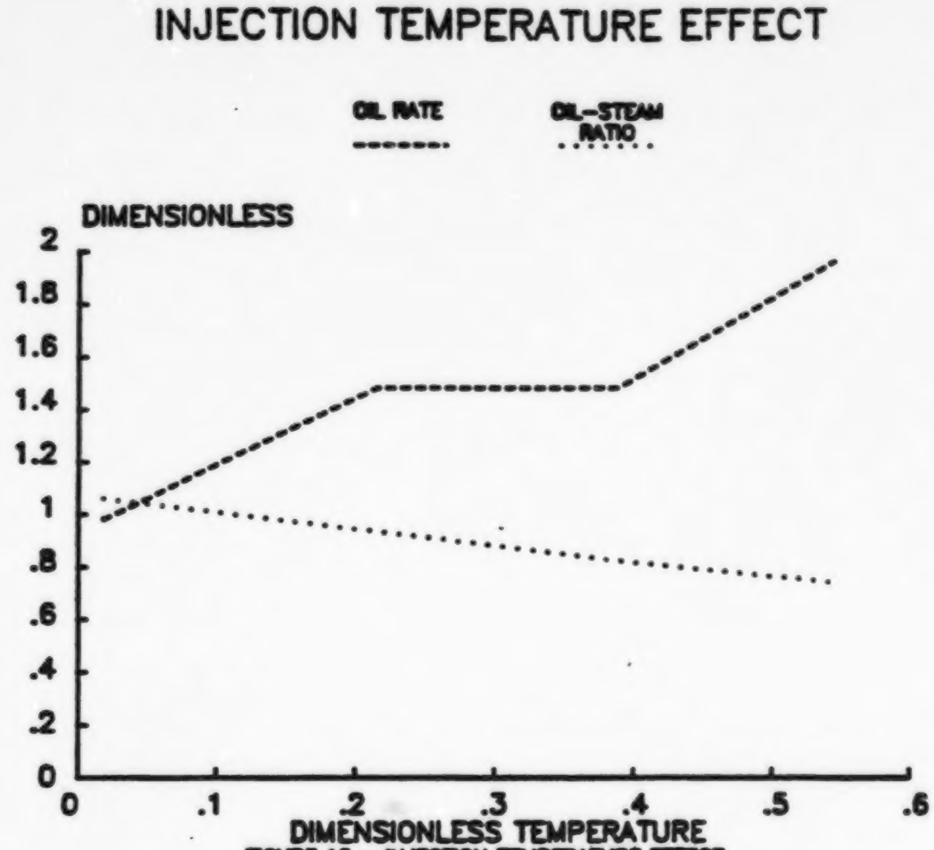

FIGURE 15 – INJECTION TEMPERATURE EFFECT

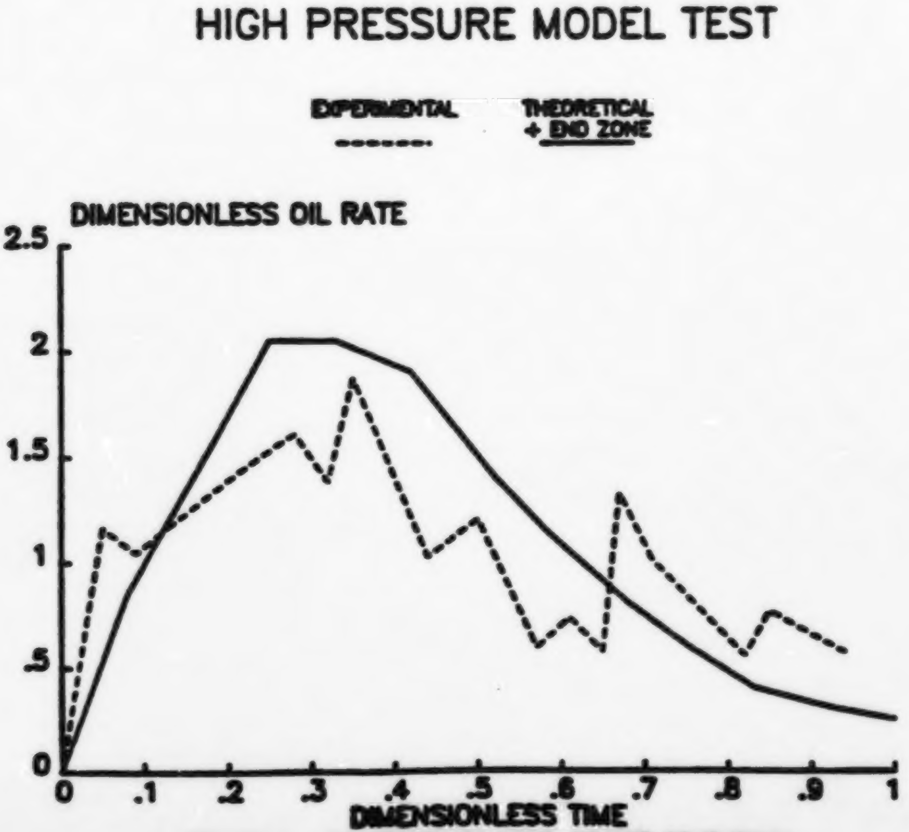

FIGURE 16 – HIGH PRESSURE MODEL REVISED COMPARISON

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67

A Laboratory Study of Thermal Oil Recovery Using Horizontal Wells

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ABSTRACT

This paper reports laboratory experimental esults of steam-assisted gravity drainage using horizontal wells. The results were obtained for 17°API heavy oil and light refined oil. The oil steam ratios and percentage recovery of original oil in place were measured for two different well configurations, injection well completions, and shale barrier configurations. In addition, the effect of limited steam entry was also studied using a light refined oil.

The experiments were conducted in a box-shaped sand pack with five sides of steel and one side of transparent polycarbonate material to facilitate flow visualization. The results indicate that steam-assisted gravity drainage not only gives a high sweep efficiency but also gives oil steam ratios of about 0.7, indicating a high thermal efficiency for producing heavy oils. Steam-assisted gravity drainage produces heavy oil at a rate approximately three times faster than that obtained with cold oil gravity drainage.

In a uniform permeability pack, initial oil production rates using horizontal injection and production wells are higher than those obtained using a vertical injector and a horizontal producer. For a vertical injector, steam injection near the pack top gave higher and faster oil recovery than steam injection near the sand pack bottom.

In the case of shale barriers, a vertical ection and horizontal production scheme gives ster and higher oil recovery as compared to that obtained using a horizontal injection and production well scheme. A light refined oil was used to obtain limited entry results, where steam injection was confined to 5 to 10% of the length of a horizontal injector. This occurs when a vertically fractured zone intersects a horizontal injection well at 90°. The results indicate that limited entry does not affect total oil recovery. On the contrary, it enhances initial oil production rates.

The above results indicate that steam-assisted gravity drainage is an efficient method for producing heavy oils.

INTRODUCTION

Gravity drainage is an important oil production mechanism because it generally produces a large portion of original oil in place, resulting in low residual oil saturation.[1-5] However, under certain circumstances, gravity drainage results in very low oil production rates, and therefore, it may be uneconomical.

In heavy oil reservoirs, a combination of steam heat and horizontal wells could be used to increase gravity drainage oil production rates. Steam heat reduces oil viscosity and a horizontal well provides a large reservoir contact area. The available laboratory data and mathematical model studies demonstrate the success of steam-assisted gravity drainage using horizontal wells in producing highly viscous bitumen (8 - 10 °API oil).[6-14] The oil production process succeeds even though bitumen is immobile at room temperature ($\mu = 10^5 - 10^6$ cp at 15°C). Many California heavy oils (>10°API) exhibit viscosity of the order of 1000 cp at room temperature. Therefore, steam-assisted gravity drainage could be a thermally efficient process for producing these heavy oils. Previously, heavy oil data for steam-assisted gravity drainage using horizontal wells were not available. This paper reports such data.

References and illustrations at end of paper.

OBJECTIVE

The objective of the present laboratory study was to evaluate steam-assisted gravity drainage using horizontal wells for producing heavy oils. In addition, the study examined the effect of well configurations and shale barriers on oil production. The influence of steam injection restricted to only a small portion of a long horizontal well was also observed. This limited entry occurs when a horizontal injection well intersects a vertically fractured zone, perpendicular to the injection plane. All experiments, other than those for a limited entry, were conducted using 17°API heavy oil (μ=800 cp at 22°C). The limited entry experiments were conducted using light refined 10 stock oil (μ=36 cp at 22°C).

Steam-Assisted Gravity Drainage Oil Production Mechanism

Figure 1 shows a schematic diagram of thermally aided gravity drainage.[6-10,14] Two horizontal wells are drilled at close spacing, one above the other. Steam is continuously injected into the top well and oil is continuously produced from the bottom production well. Other than the gravity head difference, there is virtually no pressure drop between the injection and production wells. The injected steam travels vertically upward and eventually forms a steam bubble as shown in the figure. The steam condenses at the bubble boundaries and transfers heat to the heavy oil. A heated thin layer of oil drains along the bubble boundary to the bottom production well. As time progresses the steam bubble spreads upwards and sideways, eventually hitting the reservoir top; then it starts descending giving a high sweep efficiency. Finally, when most of the oil is produced, steam breaks through the bottom production well. This process is very similar to that of a bathtub where steam travels upward and water drains below.

The major process advantage is that hot oil is produced as soon as it is displaced from the formation. In addition, nearly independent travel paths of steam, condensed hot water, and hot oil minimize relative permeability effects.

Literature Review

Since 1950 several studies have reported results of oil production using gravity drainage.[1-5] Butler and co-workers[6-9] did a pioneering experimental and mathematical bitumen production study using thermally aided gravity drainage. They developed explicit equations to calculate oil production using two parallel horizontal wells. Griffin and Trofimenkoff[10] reported experiments with Cold Lake bitumen using a vertical steam injector and horizontal producer. They also proposed an analytical solution to calculate oil production. In general, theoretical solutions show a fairly good agreement with experimental data.[6-10]

Coates[11] has described a physical simulator designed for horizontal well experiments. Toma et al.[12] have reported laboratory results using a horizontal well cyclic stimulation scheme for producing Athabasca bitumens.

Huygen and Black's[13] laboratory results wi[illegible] Alberta bitumen showed that cyclic steam is a pr[illegible]ferred production technique. They also noted that vertical fractures reduced thermal efficiency of horizontal well steamflood. It is important to note that their experiment involved conventional steamflooding, not gravity drainage. In contrast, our earlier work[14] with Alberta bitumen and light refined oil indicates that vertical fractures significantly improve thermal efficiency of steam-assisted gravity drainage. The vertical fractures we considered were parallel to the plane of a horizontal injection well. These fractures facilitated a rapid vertical rise of a steam bubble to the reservoir top along the entire injection plane. Once at the reservoir top, the steam bubble quickly spread horizontally enhancing initial oil production rates, oil steam ratios, and produced fluid oil water ratios.

Recently, a few numerical simulation studies have also been reported. Rial[15] considered conventional steam flooding using a horizontal injector and a vertical producer in a Kern River field type reservoir. His results show that in five years, the horizontal-vertical wells combination steamflood produces 64% of original oil in place (OOIP) as compared to 51% of OOIP produced using vertical injection and production wells. Jain and Khosla[16] simulated bitumen production using a 400 m (1300 ft) long horizontal production well and two vertical steam injectors. Their gravity drainage result[illegible] show production of the order of 50 m^3/day (315 [illegible]) in a 33.5 m (110 ft) thick reservoir. Their simulation production results are in fairly good agreement with Butler's[8] analytical model. Recently in Alberta, field pilots have been established to study thermally aided gravity drainage.[17-18]

EXPERIMENTAL SETUP

Figure 2 shows temperature dependent viscosity variation of 17°API heavy oil and light refined oil used in the experiments. All the experimental data reported here are for 17°API heavy oil unless noted otherwise.

Apparatus Description

Figure 3 shows a schematic diagram of the experimental apparatus. The 205 kPa (15 psig) steam from the supply line was first superheated and was injected into the cell via an orifice meter. The experimental cell was a rectangular box, 305 mm (12") wide, 102 mm (4") deep, and 254 mm (10") high with five sides constructed of steel. One 305 mm x 254 mm side was made of transparent Lexan® polycarbonate material to facilitate flow visualization. Several tube fittings were welded on the side, back, and top steel walls of the box to provide convenient locations for the injection and production wells. As shown in Fig. 4, the following two basic well configurations were studied: Scheme I include[illegible] horizontal wells, one producer and one injecto[illegible] Scheme II included a vertical steam injector an[illegible] horizontal producer.

Perforated copper tubing, 6.4 mm (¼") in diameter, was used for the injection and production wells. Several 1.6 mm (1/16") diameter holes were [illegible]illed along the lengths of the injection and pro[illegible]ction wells. These wells were covered with 100 mesh screens to prevent sand from entering the wells. Chromel-Alumel thermocouples were inserted into these wells to measure steam injection and fluid production temperatures. Injection and production well pressures were also measured. The entire apparatus, except the clear face, was well insulated with fiberglass to reduce heat losses.

The Porous Pack Preparation

In each experiment, the desired well configurations and shale barriers or fractures were installed inside the box. Several Chromel-Alumel thermocouples were also installed on the side, bottom, and top walls of the steel box. The box was then filled with 20-30 mesh (0.84 - 0.58 mm diameter) Ottawa sand for heavy oil experiments. In the case of some light oil experiments, the box was filled with the 40-50 mesh (0.43 - 0.30 mm diameter) glass beads. The pack was then evacuated and was later filled with water. The permeability of the water saturated Ottawa sand pack was about 2000 md. The weight difference between the evacuated pack and the water-filled pack was used to calculate pack pore volume and porosity. The pack was then oil flooded and the displaced water was measured to calculate oil and water saturations. Table I summarizes typical porous pack properties.

In the case of light oil, red dye was added to [illegible] oil sample to facilitate flow visualization. In the case of heavy oil runs, the color contrast between the steamed out zone and oil saturated zone was insufficient to obtain good photographs.

Experimental Procedure

In each experiment, 205 kPa (15 psig) supply steam was super-heated and flowed through the orifice meter. In general, the pressure drop in the orifice meter was maintained at about 55 kPa (8 psia), which gave a steam flow rate in cold water units of about 3.4 cc/min. A 128 to 150 kPa (4 to 7 psig) steam with about 2 to 3°F superheat was injected into the porous pack. In each experiment, there was very little pressure drop between the injection and production wells. However, the temperature difference between the two wells was substantial, especially at the beginning of a run. The steam injection temperature was about 113°C (235°F). At the beginning of an experiment, the production well temperature was about 22°C (72°F). As time progressed, with continued steam injection, the production well temperature rose. It took a few hours for the production well temperature to reach about 95°C (203°F). After that time, the throttle valve on the production line was manually operated to control the produced fluid rate which in turn controlled the produced fluid temperature. Keeping the production well temperature below 95°C ensured a liquid presence around the production well. This, [illegible]bined with a minimum pressure drop between the [illegible]ection and production well, prevented steam from short curcuiting and helped it to travel vertically upward in the pack. Produced fluid samples were collected every 30 to 60 minutes, and later they were phase-separated to measure water and oil volumes.

As noted earlier, the injected steam travels vertically upward and sideways. It rises to the reservoir top and then starts descending, giving a very high sweep efficiency. Eventually steam breaks through the production fluid, and the experiment is terminated. Some earlier papers depict steam front advancement in uniform permeability bitumen and light oil packs.[6,8,14] A little different steam front advancement was noticed in heavy oil packs with shale barriers, which is discussed later in this paper.

RESULTS AND DISCUSSION

All the results described in this section, other than those for the limited entry case, are for 17°API heavy oil. For convenience, this section is further divided into four subsections.

As noted earlier, the purpose of the present work was to study steam-assisted gravity drainage for heavy oils. Although the study was not directed to a specific reservoir, the present results could be scaled-up using dimensionless parameters proposed by Butler.[6-9] The results presented as plots depicting variation of recovery of original oil in place over time could be used to calculate oil production rates. These experimental rates, pack data (Table I), and viscosity data (Fig. 2) could be used to obtain dimensionless time and oil production parameters as suggested by Butler.[6-9]

Influence of Well Configuration

Results were obtained using two well configurations: Scheme I includes horizontal injection and production wells, and Scheme II includes a vertical injection well and a horizontal production well. Figures 5 and 6 compare oil steam ratios (OSR) and percentage recovery of original oil in place (OOIP) for the two schemes, respectively. As seen in the figures, the horizontal well pair (Scheme I) produces more oil and gives a higher oil-steam ratio than those obtained using a vertical injector and horizontal producer (Scheme II). As soon as steam injection begins, the entire horizontal production length starts producing hot oil in a parallel horizontal well pair scheme. This results in a high initial OSR and high initial oil recovery. Conversely, in a vertical injector and horizontal production scheme, initially hot oil production is limited to a small portion of the horizontal producer, which is directly below the injector. The rest of the horizontal producer carries gravity produced cold oil. It takes a period of time for the steam bubble to expand and for the entire production well to produce hot oil. This shows that initial oil production rates could be strongly dependent upon the number of vertical injectors located along the length of a horizontal producer. However, after about 0.35 pore volumes of steam injection, oil steam ratios for both schemes are similar. In addition, the final percentage recovery of OOIP is about 80% for both schemes.

Comparison With Theoretical Results

Figures 7 and 8 compare the experimental and theoretical[6-10] steam-assisted gravity drainage production. The percentage recovery of OOIP is plotted against time in minutes. For comparison, experimental data for cold oil gravity drainage are also included in Fig. 7. These data were obtained using a horizontal production well and imposing a 103 kPa (0.25 psig) nitrogen pressure at the pack top. As seen in Fig. 7, after 600 minutes, cold gravity drainage produced 23% of OOIP. At the same time, steam-assisted gravity drainage theory predicts 48% recovery of OOIP while the experimental data showed 75% recovery of OOIP. Thus, steam-assisted gravity drainage produces oil at a rate approximately 3 times faster than that obtained using cold oil gravity drainage.

For steam-assisted gravity drainage, theoretical solutions[6-10] were developed for bitumen production. The theory assumes mobile oil to be present near the steam front; everywhere else, oil is assumed to be immobile. Figure 7 shows an excellent agreement between the theoretical solution and experimental results for Scheme I (a horizontal well pair) for the first 310 minutes, i.e., up to 0.43 pore volumes of water equivalent of steam injection. After this point, the experimental results show substantially higher recovery than that predicted by theory. The higher experimental oil production could be explained by temperature measurements. The temperature measurements show that it takes about 310 minutes for the steam bubble to reach the cell top. There, it rapidly spreads horizontally, contacting a large portion of heavy oil, and resulting in the observed increased oil production.

Figure 8 compares experimental and theoretical results for the vertical injection and horizontal production scheme. The experiments were conducted using two different injection well completions as shown in Fig. 8. In case A, steam was injected through the injection tubing at the bottom of the 'casing', and then it rose vertically through the annulus. This ensured a hot path, almost at steam temperature, to the displaced oil up to the vicinity of the production well. As seen in Figure 8, the experimental oil recovery results are a little higher than those predicted using theory. Here also, when steam reaches the reservoir top, increased oil production is noticed.

In the case of a vertical injector and a horizontal producer, results were also obtained using another steam injection method, called Case B. As shown in Fig. 8, in Case B, steam was directly injected at the top of a perforated vertical injector. At the beginning, most of the injected steam entered only the top portion of the pack, and quickly spread horizontally. As time progressed, a uniform horizontal steam front started gradually descending, towards the production well, giving a high sweep efficiency. As shown in Fig. 8, this resulted in higher and more rapid oil recovery than obtained using the Case A injection method.

For bitumen production, the proximity of the steam injection point and the oil production point is essential. The present results show that for heavy oil, which has limited mobility at reservoir temperature, steam-assisted gravity drainage could also be successfully accomplished by injecting steam near the reservoir top through a vertical injector.

Influence of Shale Barriers

Figure 9 shows the two geometric shale barrie[illegible] configurations used in the experiments. Shale barriers were simulated by using 6 mm thick Ryton® plastic sheets. The thermal diffusivity of the water saturated Ottawa sand[19] is about 39.9 cm^2/hr (0.043 ft^2/hr) while that of impermeable Ryton® sheet[20] is about 7.3 (0.0079 ft^2/hr). For each shale barrier case shown in Fig. 9, experiments were conducted using both well configuration schemes noted in Fig. 4. Figure 10 shows typical steam front progress with the shale barrier Scheme A using a horizontal well pair. Despite the shale barrier, steam-assisted gravity drainage exhibits a high sweep efficiency. In addition, as shown in Fig. 11, the final percentage recovery of OOIP with steam-assisted gravity drainage is almost the same with and without the shale barrier. To obtain the same final oil recovery, a reservoir with shale barriers requires a little longer time and more steam than that required in a uniform permeability reservoir. Figure 11 also includes plots of oil steam ratios for a horizontal well pair scheme with two different shale barrier configurations. These data also show extra steam injection required with the shale barriers. For a horizontal well pair, shale barrier configuration B requires much more steam than that required for shale configuration A. Thus, in a reservoir with shale barriers, a preferable well location for a horizontal well pair is below a shale barrier discontinuity.

Figure 12 shows the influence of shale barri[illegible] on oil recovery from a vertical injection and horizontal production scheme. The figure shows that the sand pack with shale barriers initially produce oil at a faster rate than that obtained in a uniform permeability pack. This could be because the shale barrier helps initially to divert the injected steam to the top portion of the reservoir and accelerate oil production. However, as steam injection continues, shale barrier Scheme B, shows a little smaller oil production rate than that obtained in a uniform permeability pack. The final oil recovery with shale barrier Scheme B is the same as that obtained in a uniform permeability pack. However, shale barrier Scheme B requires a longer time and more steam than that required in the uniform permeability pack. In the case of shale barrier Scheme A, the oil recovery is faster than that obtained in a uniform permeability pack. However, its final recovery is only 75%, leaving a large portion of oil in the reservoir as compared to shale barrier Scheme B and uniform permeability pack.

Figures 13 and 14 are crossplots of Figures 11 and 12. These figures show oil recovery using two different well configuration schemes for a given shale barrier geometry. As seen in Figs. 13 and [illegible] for shale barrier configurations A and B, faster oil production is obtained using a vertical injector and horizontal producer than using a horizontal well pair.

Limited Entry Results

As noted earlier, sometimes a horizontal injection well may intersect a vertical fracture which is perpendicular to the injection plane. This may result in diversion of most of the injected steam to the fractured zone, and the rest of the injector could be unutilized. This condition was simulated using vertical fractures perpendicular to the injection plane. The vertical fractures were made of 100 mesh wire screens. As shown in Figs. 15 and 16, the fractured zone was restricted to 5 to 10% of the injection well length. The fractures covered the entire depth of the experimental pack. During the experiments, most of the injected steam traveled vertically upward through a fractured zone reaching rapidly to the reservoir top. As time progressed it developed an inclined bubble. Figures 14 and 15 show plots of oil steam ratios and oil recovery for various limited entry configurations. It is important to note that the results plotted in Figs. 15 and 16 were obtained using light refined oil in a 40-50 mesh glass bead pack described in Table I. The figures clearly show that limited entry enhances vertical steam rise and results in higher initial oil steam ratios. The observed results are similar to those obtained using vertical fractures which were parallel to the horizontal injection plane.[14] Thus, limited entry does not impair the efficiency of thermally aided gravity drainage. On the contrary, it enhances initial oil production.

CONCLUSIONS

The laboratory data presented here demonstrate the success of thermally aided gravity drainage in producing heavy oils. In general, steam-assisted gravity drainage produces heavy oil at a rate approximately three times faster than that obtained with cold oil gravity drainage. The oil steam ratios of the order of 0.7 indicate the high thermal efficiency of the process. In a uniform permeability reservoir, a horizontal well pair gives high initial oil production. However, the final oil recovery obtained using either a horizontal well pair or a vertical injector and horizontal producer is almost the same.

In reservoirs with shale barriers, a vertical injection and horizontal production scheme gives faster oil recovery than that obtained using a horizontal well pair. The shale barriers obstruct development of the steam bubble. The drop in the process thermal efficiency due to the shale barriers, as studied in this paper, is not significant. To obtain the same final oil recovery, reservoirs with shale barriers require a little longer time and more steam than that required in a uniform permeability reservoir.

The data presented here indicate that limited steam entry caused by vertical fractures, perpendicular to the horizontal injection plane, does not adversely affect the gravity drainage process. On the contrary, vertical fractures provide an easy path for vertically upward steam travel resulting in high initial oil production.

ACKNOWLEDGEMENTS

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TABLE I: Porous Pack Details

	Heavy Oil Pack	Light Oil Pack
Sand Size (Mesh)	20-30	40-50
Porosity	0.33	0.33
Permeability (md)	1600-2500	800-1000
Initial Oil Saturation (% volumetric)	90	94
Initial Water Saturation (% volumetric)	10	6

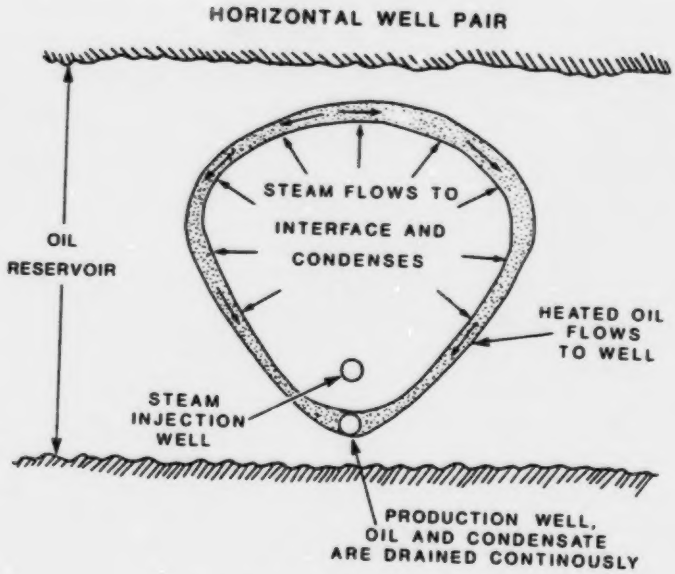

HORIZONTAL WELL PAIR
OIL RESERVOIR
STEAM FLOWS TO INTERFACE AND CONDENSES
HEATED OIL FLOWS TO WELL
STEAM INJECTION WELL
PRODUCTION WELL, OIL AND CONDENSATE ARE DRAINED CONTINOUSLY

Fig. 1—Steam-assisted gravity drainage concept.

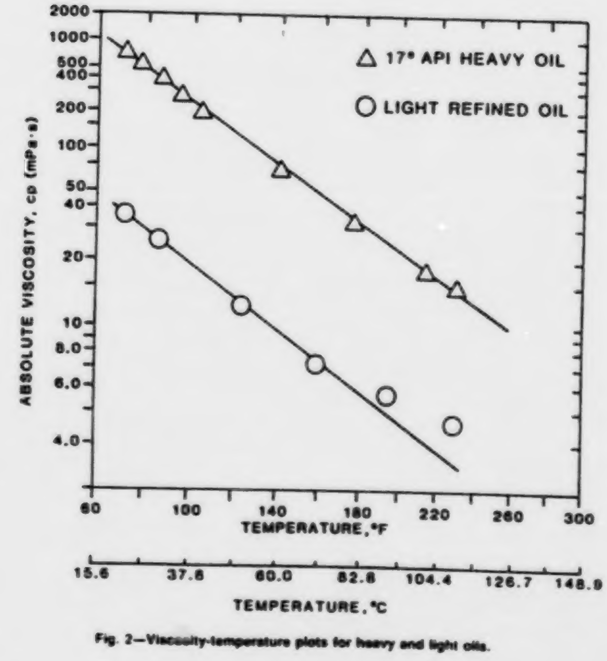


Fig. 2—Viscosity-temperature plots for heavy and light oils.

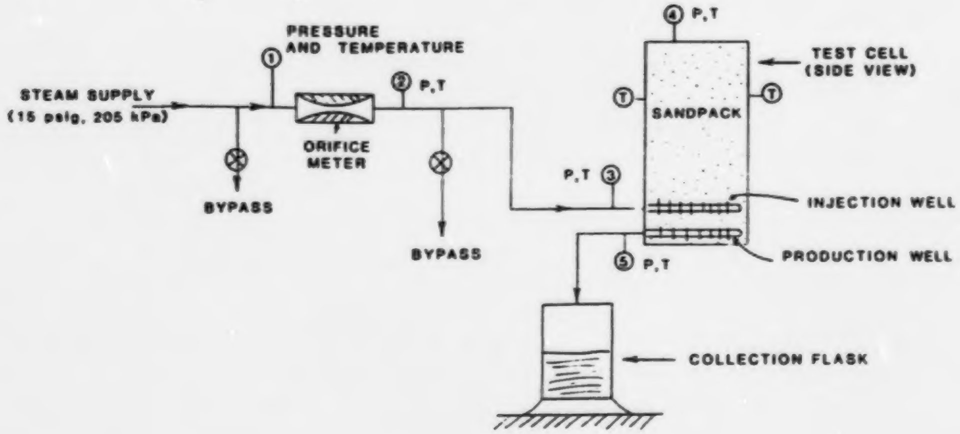


Fig. 3—Schematic of experimental equipment.

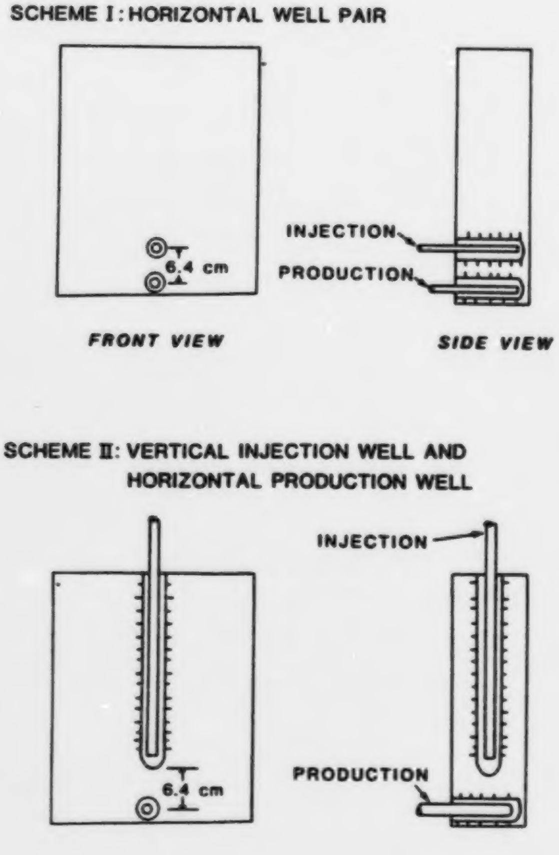

SCHEME I: HORIZONTAL WELL PAIR
6.4 cm
INJECTION
PRODUCTION
FRONT VIEW
SIDE VIEW
SCHEME II: VERTICAL INJECTION WELL AND HORIZONTAL PRODUCTION WELL
INJECTION
6.4 cm
PRODUCTION

Fig. 4—Experimental well configurations.

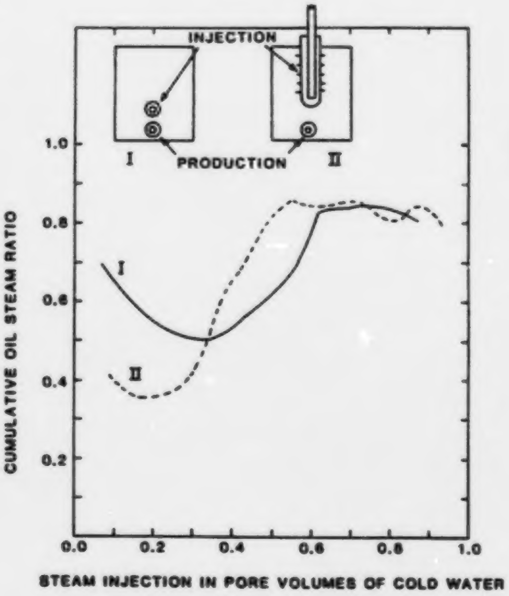


Fig. 5—A comparison of oil/steam ratios for two different well configuration schemes.

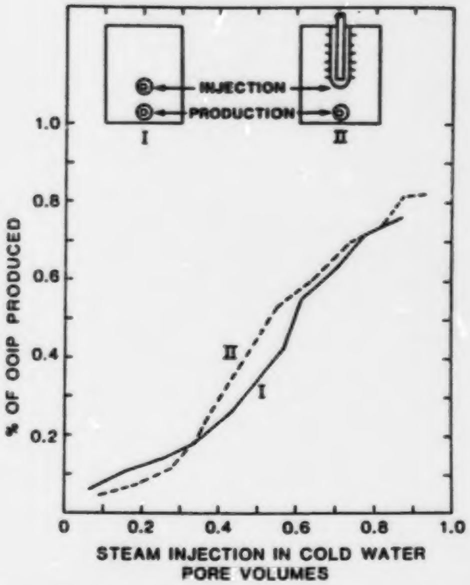


Fig. 6—A comparison of percentage recovery of OOIP for two different well configuration schemes.

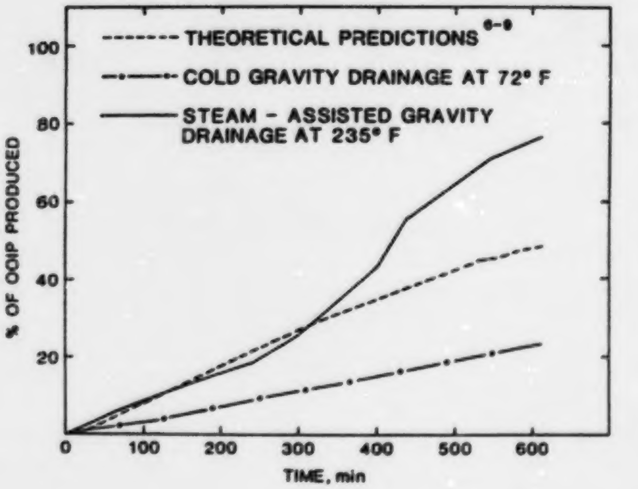


Fig. 7—A comparison of theoretical and experimental oil recovery for the horizontal injection and production wells scheme.

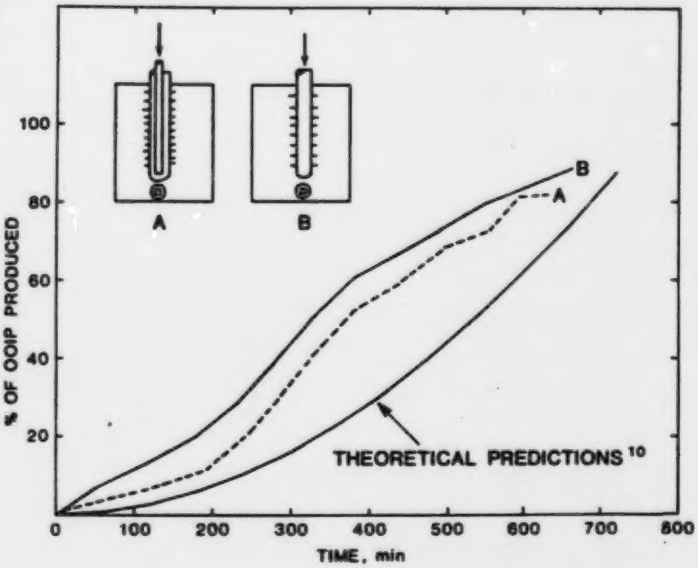


Fig. 8—A comparison of theoretical and experimental oil recovery for a vertical injector and a horizontal producer scheme. Experimental results were obtained using two different well completion schemes.

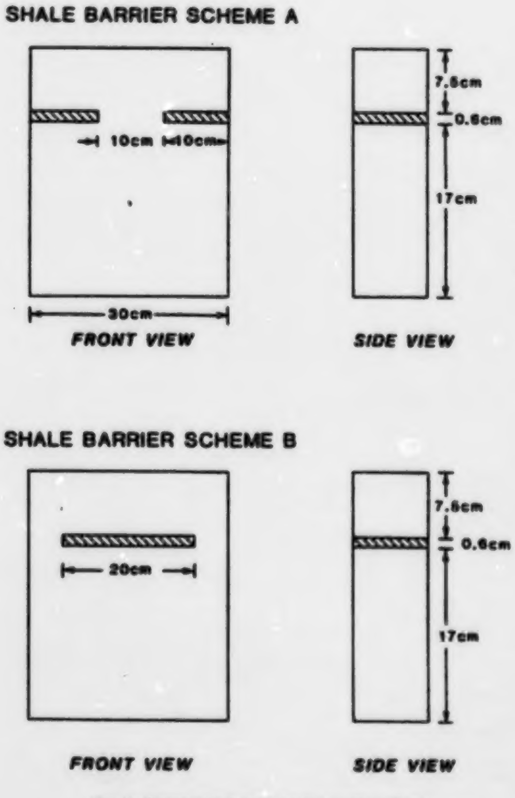
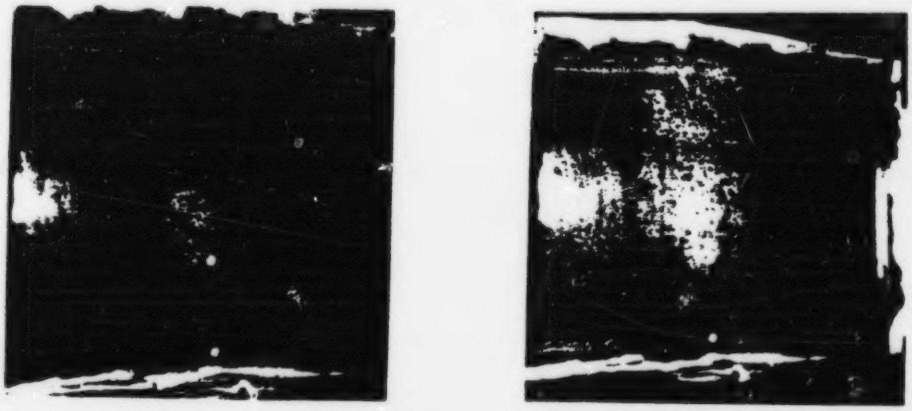
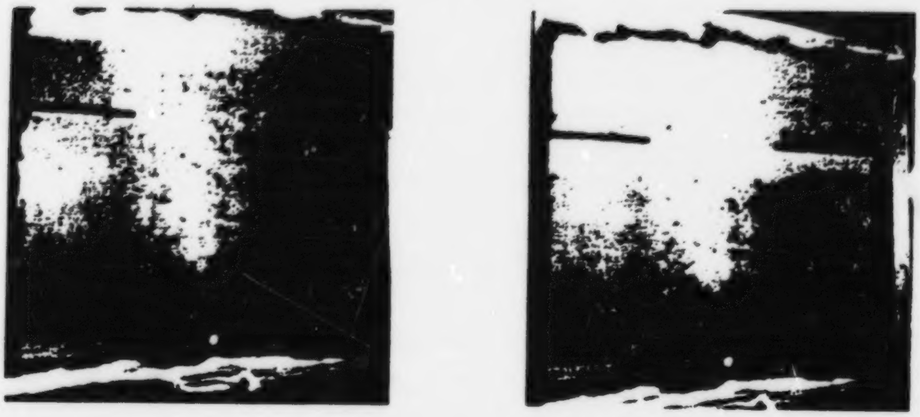


Fig. 9—Experimental shale barrier configurations.



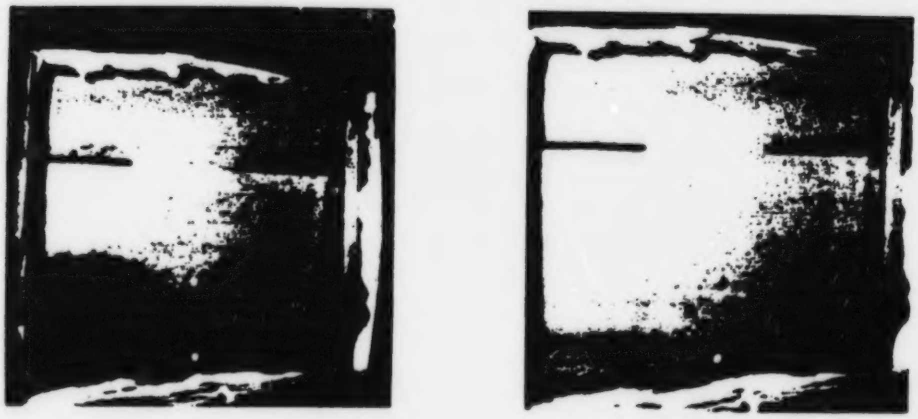
Elapsed Time: 75 minutes

Elapsed Time: 255 minutes



Elapsed Time: 375 minutes

Elapsed Time: 495 minutes



Elapsed Time: 548 minutes

Elapsed Time: 721 minutes

Fig. 10—Typical steam front progress with shale barrier Scheme A and a horizontal well pair configuration. The photographs were obtained using light refined oil.

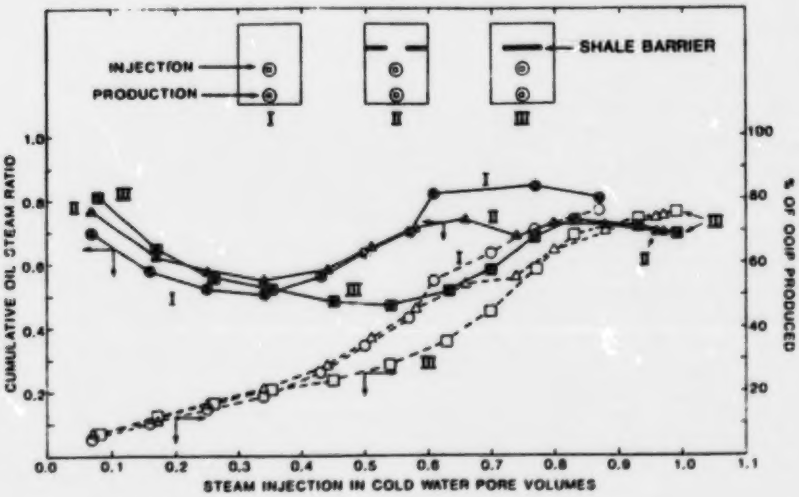


Fig. 11—The influence of shale barrier configurations on oil production using a horizontal well pair scheme.

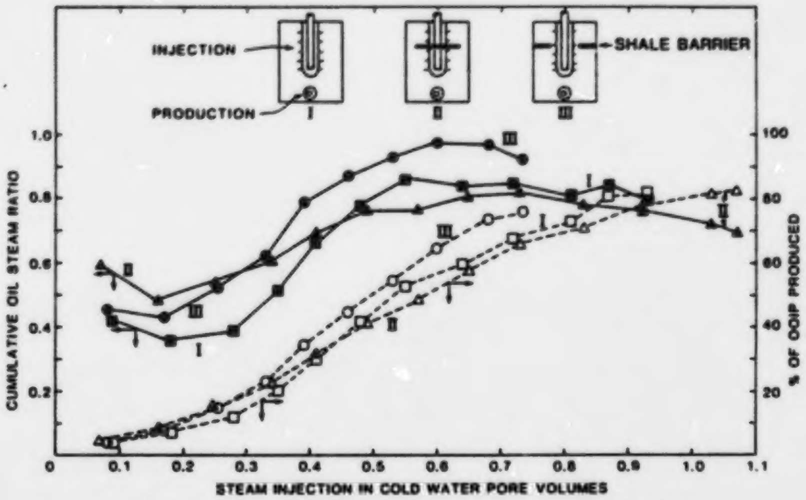


Fig. 12—The influence of shale barrier configurations on oil production using a vertical injector and horizontal producer.

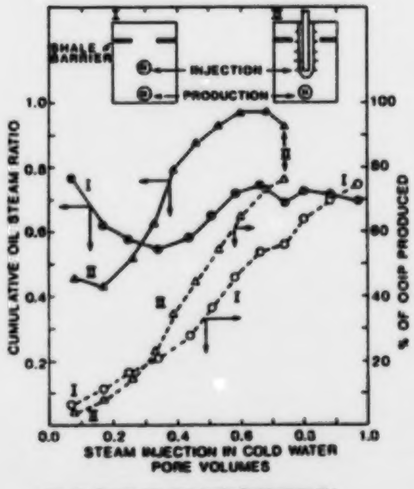


Fig. 13—Results with shale barrier Configuration 'A.'

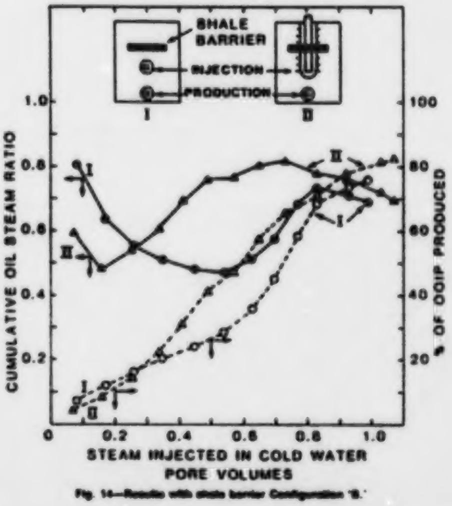


Fig. 14—Results with shale barrier Configuration 'B.'

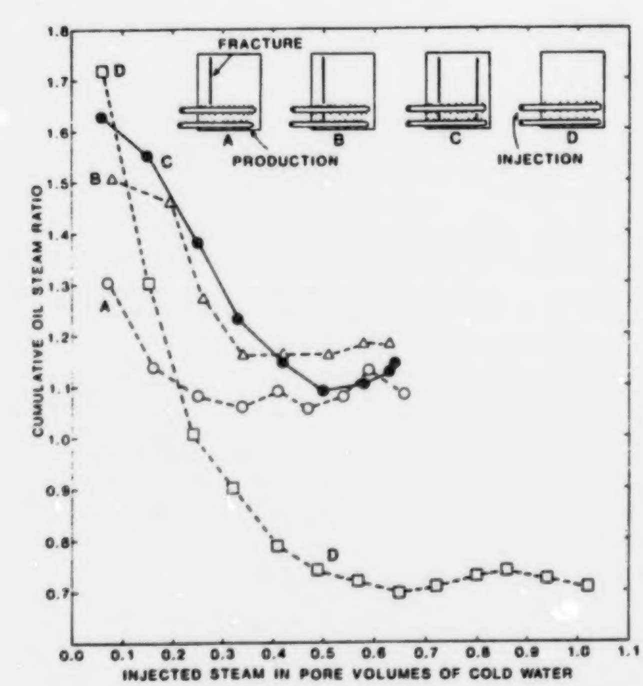


Fig. 15—The influence of various limited-entry configurations on cumulative oil/steam ratio (light refined oil results).

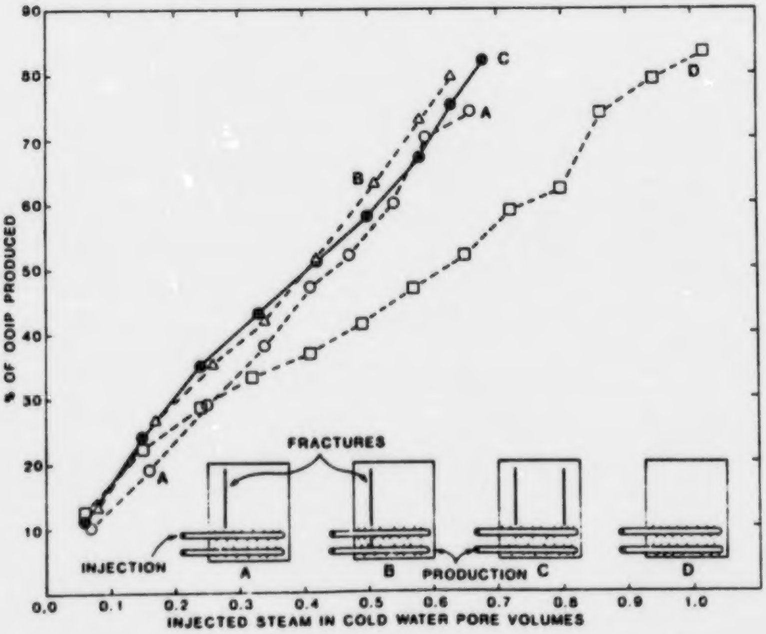


Fig. 16—The influence of various limited-entry configurations on percentages of OOIP recovered (light refined oil results)

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SESSION 1

PAPER 2

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LABORATORY STUDIES OF THERMALLY-AIDED GRAVITY DRAINAGE MECHANISM USING HORIZONTAL WELLS

(68)

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Technology" Conference

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Calgary, Alberta, Canada

LABORATORY STUDIES OF THERMALLY AIDED GRAVITY DRAINAGE USING HORIZONTAL WELLS

by

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ABSTRACT

A thermally aided gravity drainage mechanism using a horizontal well was studied experimentally. The laboratory apparatus was a glass bead packed rectangular steel box with one transparent wall allowing flow visualization. Data were obtained for three different well configurations consisting of a horizontal injection and production well pair, a vertical steam injection well and a horizontal production well pair, and a single vertical well used for both injection and production. Results indicate that the horizontal well pair gives maximum oil recovery.

The effect of fractures and highly premeable zones on a gravity drainage mechanism was also investigated. Results show that certain vertical fracture configurations may help the gravity drainage process.

INTRODUCTION

For many years gravity drainage has been regarded as an important oil productio mechanism. In general, oil production by gravity drainage results in a lowe residual oil saturation than other production methods, and consequently highe recovery of the original oil in place (OOIP). However, oil production rate from conventional vertical wells using gravity drainage are normally too low t be economically viable. In the past, pressure maintenance, steam injection an more recently horizontal production wells have been used to increase oi production rates. This suggests significantly higher oil production rates usin gravity drainage could be achieved by a combination of effective steam injectio and horizontal production wells. The oil viscosity reduction from steam heatin and increased reservoir contact achieved through horizontal wells seems mor likely to give economically viable oil production rates.

OBJECTIVE

The objective of this work was to study oil production with thermally aide gravity drainage using horizontal wells and to evaluate the effects of variou well configuration schemes and vertical fractures.

REVIEW OF LITERATURE

The idea of using horizontal drainholes dates back to the early 1950's (1,2,3 Higgins (3) conducted laboratory experiments with various crudes (12-25° API) a different temperatures (70-270°F). He noted that uniform heating of the poro pack is essential to recover a large percentage of the OOIP. However, he d not suggest a definite method to uniformly heat the heavy oil reservoir. Terwillinger et al. (4) reported experimental data and a mathematical analysis of the gravity drainage problem. A classical Buckley and Leverett type solution was devised. The mathematical solution of the gravity drainage problem was also reported by several other investigators (5 to 9). Perrine (7) noted that oil production using horizontal drainholes is strongly dependent upon the length of a drainhole. The spacing of drainholes and their arrangement has little influence on the oil production. Dykstra (8) gave an analytical solution to calculate oil production rates. Hagoort (9) recognized the importance of oil relative permeability. In general, he observed that the residual oil saturations in the gravity drainage process are much lower than those found in other oil producing mechanisms. In addition, oil producing rates using gravity drainage are fairly constant over a long time period. Recently, Giger and associates (10, 11) proposed correlations to calculate oil production rates using horizontal wells. The effect of fractures was also included.

Pioneering work on steam assisted oil gravity drainage was reported by Butler and associates (12, 13). The important concept of oil displacement through the thin boundary layer next to the expanding steam chamber was introduced. They reported experimental data as well as a semi analytical-numerical solution. Their laboratory experimental data are in fairly good agreement with their theoretical solution. Their results indicate that for maximum oil production efficiency a process requires continuous steam injection and continuous oil drainage. However, for the fractured reservoir, Huygen and Black's (14) laboratory results indicate cyclic steam stimulation using a horizontal well is the

best production technique. They also reported that vertical fractures are no ideal for steam flooding using horizontal wells.

Engineering intuition indicates that vertical fractures should aid gravit drainage. Furthermore, they should be even more helpful for thermally aide gravity drainage where high permeability fracture channels could aid a vertically upward flow of low density steam as well as the downward flow of heated oi and condensate in initially forming the bubble. Preliminary field results fro the Rospo-Mare field (offshore Italy) obtained by Elf-Aquitaine (15, 16) indicate the usefulness of vertical fractures for gravity drainage using horizontal well. However, no field data are available in the literature fo steam assisted gravity drainage using horizontal wells.

CONCEPT

a) Thermally Aided Gravity Drainage Using Horizontal Wells

The process concept is depicted in Figure 1. The steam injection an production wells are horizontal and are located one above the other an physically as close as possible. This well pair is drilled and complete near the bottom of the reservoir oil column. The steam is injected continuously in the upper well. The steam, being low density, travels vertically upward and forms a steam bubble. Steam condenses at the bubbl boundary and heats oil around its periphery. A thin boundary layer of hot low viscosity oil is formed ahead of the steam bubble front. This mobilized oil drains along the bubble boundary directly towards the productio well. The pore space vacated by oil drainage is then invaded by the steam bubble. Thus, as time progresses, oil keeps draining and the steam bubble keeps growing upward and outward. Eventually, it will reach the top reservoir boundary and will start moving rapidly sideways and downward until it drains almost the entire effective reservoir area.

It is important to note that there is essentially no pressure drop between the injection and production wells. The drainage rate in the production well is adjusted to control bottom hole pressure and temperature so that only liquid exists in and around the production well. This liquid leg around the production well prevents steam from short circuiting from the injection well to the production well. The process here is similar to what happens in a bathtub where hot steam travels upward and hot water drains through the bottom drainhole. The advantages of steam assisted gravity drainage using a horizontal well are:

1) When heated, the oil moves directly to the production well utilizing gravitational force and is not required to displace unheated oil.

2) There are almost independent flow paths for the oil and water resulting in an increased relative permeability to oil flow.

3) The large reservoir contact area results in an increased oil production rate.

4) The amount of steam injected is just sufficient to supply heat consumption and to replace oil volume displaced from the formation. This results in low steam injection rates, high oil steam ratios (OSR), and high produced oil water ratios (OWR).

5) The process mechanism takes advantage of natural convection heat transfer which results in a high reservoir sweep efficiency.

b) Well Configurations

The field application of thermally aided gravity drainage processes is possible by employing three different well configuration schemes as shown in Figure 2. These schemes are described below:

Scheme I: A Horizontal Well Pair.

Two horizontal wells are drilled with one placed slightly above the other. The steam is injected into the top well and oil and water are produced from the bottom well.

Scheme II: Vertical Steam Injection Wells and a Horizontal Production Well.

Steam is injected into several vertical wells placed above and along the length of a horizontal production well.

Scheme III: Single Vertical Injection and Production Well.

Steam is injected into the formation through the annulus and perforations in the top portion of the reservoir, and fluids are produced at the well bottom perforations through tubing. A packer is used to separate injection and production flow as shown in Figure 2.

c) Fracture Orientation

There are several heavy oil reservoirs which are heavily fractured. Past experience indicates that, in general, it is difficult to produce oil from a vertically fractured reservoir using a vertical well. In addition, many bitumen reservoirs have very low steam injectivity. Hence, steam injection above fracture pressure is necessary to start and sustain sufficient steam injectivity. Most of these reservoirs are shallow ($\leq$ 2000 ft.) and induced fractures are likely to be vertical. The following three fracture configurations were studied using the horizontal well pair (Scheme I).

1) **Fracture A**, Widely spaced vertical fractures located only above the injection well.

2) **Fracture B**, Widely spaced vertical fractures above the injection well and a fracture also between the injection and production wells.

3) **Fracture C**, Closely spaced vertical fractures above the injection well and a fracture between the injection and production wells.

EXPERIMENTAL SETUP

Experiments were conducted with a light refined oil as well as with bitumen. The bitumen used was produced during steam stimulation of a well in the Primrose Field, Alberta, Canada. A temperature viscosity plot of these oils is shown in Figure 3. The majority of the experiments were conducted with the light oil since it could be dyed and photographed, and a single experiment could be completed in 4 to 8 hours. Similar experiments with bitumen took about 12-15 hours. Other than the time duration, comparable results were obtained in both cases.

a) Apparatus Description

A schematic diagram of the experimental setup is shown in Figure 4. The 15 psig (205 kPa) steam from the supply line was first superheated and then injected into the experimental cell via an orifice meter used to measure steam flow rate. The experimental cell was a square box packed with glass beads. The box was 12" (305 mm) wide, 4" (102 mm) deep and 10" (254 mm) high with five sides made out of steel. One 12" x 10" side was made out of transparent Lexan® polycarbonate material to allow observation and photography of flow patterns. Several tube fittings were welded along the side, back, top and bottom steel walls of the box so that injection and production wells could be placed conveniently at various locations. The experimental well arrangements used to simulate three different well configurations are shown in Figure 5.

The production and injection wells were made from ¼" (6.4 mm) copper tubing which was perforated with 1/16" (1.6 mm) diameter holes. These wells were covered with 100 mesh screens to prevent the glass beads from entering the wells. Chromel-Alumel thermocouples were inserted into these wells to measure steam injection and fluid production temperatures. Injection and production well pressures were also measured. For heavy oil experiments, the wells were slightly modified to facilitate initial cyclic steam stimulation until steam injectivity was established. Throttle control valves were installed on injection and production well lines. The throttle valve on the production line was operated manually to control the production rate which consequently controlled the temperature of the production well. The entire apparatus except the clear face was well insulated with fiberglass to reduce heat losses.

b) The Porous Pack Preparation.

In each experiment the desired well configuration and fracture configuration were installed in the experimental cell which was then packed with glass beads. The 40-50 mesh size glass beads (0.43 - 0.30 mm diameter) were used for light oil experiments while 20 - 30 mesh (0.84 -0.58 mm diameter) size Ottawa sand was used for heavy oil experiments. The porous pack was evacuated and flushed with CO_2. Water was then circulated through the pack until all CO_2 was displaced. This was determined by measuring the pH of the water coming out of the pack. The permeability of the pack estimated during water flooding was about 700 md. The difference between the weight of the evacuated pack and the weight of the waterfilled pack was used to calculate the pack pore volume. The water was then displaced from the pack by an oil flood. In the case of light oil, circulation was continued until no water was produced from the pack. This gave a residual water saturation of about 5 to 10%. The relative oil permeability at residual water saturation was also measured. To facilitate flow visualization a red dye was used to color the light oil. The dye gave an excellent color contrast between steamed out zones and the oil saturated zones. As expected, it was difficult to define zones with bitumen because of the limited color contrast. In saturating the pack with bitumen, it was necessary to heat the porous pack and bitumen to 180°F (82°C) prior to and during oil flooding. The typical properties of the porous pack are given in Table 1.

c) Experimental Procedure.

In each experiment, 4 to 7 psig (129-150 kPa) steam with 2 to 3°F of superheat was injected into the porous pack through the injection well. Although only a small pressure drop existed between the injection and production wells, there was a significant temperature difference between the two wells. At the beginning of steam injection, the production well temperature was about 72°F (22°C). As time progresses, the temperature of the produced fluid measured at the production well increased. This temperature was not allowed to exceed 180-190°F (82-88°C) so that a liquid leg (sump) would always exist around it. As noted earlier, the throttle valve on the production line was used to control fluid flow rate which in turn controlled the production well temperature. The presence of a liquid leg around the production well and the limited pressure drop between the injection and production wells prevented steam short circuiting. This helped low density steam to rise upward and form a bubble above the injection well. The progress of the steam bubble front with time is shown in Figure 6. As seen in the figure, when most of the reservoir was swept, the steam broke through to the production well and the experiment was terminated. Fluid samples were normally collected at one hour intervals and later separated to measure oil-water ratios (OWR).

RESULTS AND DISCUSSION

All the results which are described here are for the light oil unless otherwise noted. The oil production process described here is controlled by the fluid production rate. Therefore, most experimental results are plotted against the pore volume of produced fluid.

a) Well Configuration Results

Figures 7 and 8 show cumulative volumetric oil water ratios (OWR) and the percentage of original oil in place (OOIP) recovered, respectively, for various production schemes. The initial OWR with a horizontal well pair (Scheme I) is much larger than that for the two other schemes as a result of the higher initial oil production rate. However, this initial OWR

declines more rapidly for Scheme I than for the other schemes, and after fluid production of about 60% of a pore volume the OWR's are almost equal. Figure 8 indicates that the horizontal well pair scheme will recover more oil than the other two schemes. Greater effectiveness is achieved with this configuration because it heats the reservoir more uniformly. This observation is consistent with the criterion for high recovery observed by Higgins (3).

Data plotted in Figures 7 and 8 for well configuration Schemes I and II are for experiments which lasted about four hours. However, data for Scheme III is for an experiment of six hour duration. Attempts to run experiments faster with Scheme III resulted in a premature steam breakthrough. This indicates each scheme may have a different optimum fluid production and steam injection rate.

b) Effect of Fluid Production Rate.

The effect of fluid production rate (or steam injection rate) on oil recovery for the horizontal well pair configuration (Scheme I) is shown in Figures 9 and 10. In Figure 9, the experimental results are also compared with the analytical solution of Butler et al. (12, 13). This mathematical solution is based only on the gravity drainage effects. However, in practice some pressure effects are also present which could be used advantageously to inject steam at a slightly higher rate and produce oil faster than that predicted by the analytical solution. Nevertheless, steam injection or fluid production rate is limited by a critical rate which would result in early steam breakthrough and an excessive rate of water production. Thus, there is an optimum rate of fluid production or steam injection for each well configuration scheme. This is clearly shown in Figure 10 for the horizontal well pair configuration.

c) Results with Vertical Fractures.

As noted earlier, the length, density, and distribution of vertical fractures is important for heavy oil recovery. The influence of fracture distribution on OWR, OSR (oil steam ratio), and oil recovery was studied using the horizontal well pair scheme. The fractures were simulated by placing into the pack 4" x 4" (92 mm x 92 mm), 100 mesh stainless-steel screens which were attached to the steel body of the porous pack using epoxy. All fractures were located along the length of (or parallel to) injection and production wells. The experimental configurations of the three fracture schemes, previously referred to as A, B and C, are shown in Figure 11.

In general, it was necessary to run fracture experiments a little slower than the optimum rate found with the horizontal well pair configuration without fractures. This was especially true in schemes where a fracture was located between the injection and production wells. Therefore, the comparison of various fracture schemes is based on the total volume of the water equivalent of steam injection. The base case of a horizontal well

pair with no fractures (uniform permeability) is chosen as one which comes close to the analytical solution shown in Figure 9.

The shape and growth of the steam bubble in a fractured pack is different from that observed in the uniform permeability pack. In the uniform permeability pack the initial steam bubble shape was almost round (see Figure 6). However, in a fractured pack the vertical fracture above the injection well provides an easy path for steam to travel vertically upward directly towards the top of the pack. Initially, this results in an elongated steam bubble as shown in Figure 12. After reaching the top of the pack this thin steam bubble spreads laterally in a mushroom type fashion contacting oil located in the top portion of the pack. This oil has the highest available gravity head and hence, it drains rapidly when heated by the steam. This results in a high initial oil production rate. However, as the steam bubble expands downward the influence of the vertical fracture above the injection well declines. This fracture can no longer provide an easy path for steam to spread into the previously unswept area, resulting in a decline of the initially high OWR. This is shown in Figure 13. In the uniform permeability pack the initial OWR is about 4.8 which eventually declines to 1.8. However, with widely spaced vertical fractures (Fracture Scheme A), the initial OWR is about 10 demonstrating a significant improvement. An even better initial OWR was obtained when an additional fracture was introduced between the injection and production wells (Fracture Scheme B). This additional fracture provides an easier path for displaced oil to travel towards the production well. The best results were obtained with Fracture Scheme C where fracture density above the injection well was higher than that between the injection and production wells. The very high permeability path (fractures) above the injection well aids the natural convection of steam resulting in an efficient oil drainage. The heat transfer and fluid flow were so favorable that the initial OWR was almost infinite i.e. 100% oil production with no water production.

The effect of various fracture schemes on oil steam ratios (OSR) is shown in Figure 14. It is important to note that even with the horizontal well pair configuration (Scheme 1) in a uniform permeability reservoir, the initial OSR is about 1.6 which eventually declines to 1.3. This is significantly higher than that generally observed either with cyclic steam stimulation (OSR = 0.6 - 0.8) or with steam drive (OSR = 0.3 -0.6). This high OSR demonstrates the high thermal efficiency of the steam assisted gravity drainage process. These OSR values are further improved by vertical fractures. As shown in Figure 14, initial OSR's of about 1.8 are seen with the fractured reservoirs. It is interesting to note that in all fracture schemes, the OSR values are greater than those obtained with a uniform permeability pack until at least 25 percent of a pore volume of steam is injected. As noted earlier, this is due to the effectiveness of vertical fractures in providing steam an easy access path to the previously unswept area. The ratio of permeability between the injection and production wells and the permeability above the injection well determine the OSR values. Fracture Scheme C has a more favorable permeability ratio

than that for Fracture Scheme A. Therefore, consistently higher OSR values are obtained with Scheme C than with Scheme A.

Finally Figure 15 shows the oil recovery with the different schemes. Once again, initially higher recovery with vertical fractures as compared to a uniform permeability reservoir is obvious. The high initial oil recovery with vertical fractures will help to improve the economics of the already favorable process.

CONCLUSION

Experimental results demonstrate that steam assisted gravity drainage is a thermally efficient oil production mechanism. The horizontal well pair scheme gives higher oil production rates, higher recovery of original oil in place, and higher oil water ratios than the other two production schemes examined. Fairly high oil steam ratios of the order of one and above were also observed. These OSR's are significantly higher than those observed in conventional cyclic steam stimulation or in steam flooding. The experimental results also indicate that vertical fractures help the steam assisted gravity drainage. The fractured pack gave higher oil steam ratios and oil water ratios than those observed in the uniform permeability reservoir. Thus, existing or induced vertical fractures could be used to augment initial oil production rates.

ACKNOWLEDGEMENTS

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TABLE I

POROUS PACK DESCRIPTION

Variable	Light Oil Pack	Bitumen Pack
Sand Size (Mesh)	40-50	20-30
Porosity	0.34	0.32
Permeability (md)	600-1000	2500-3500
Initial Oil Saturation (% volumetric)	94	87
Initial Water Saturation (% volumetric)	6	13

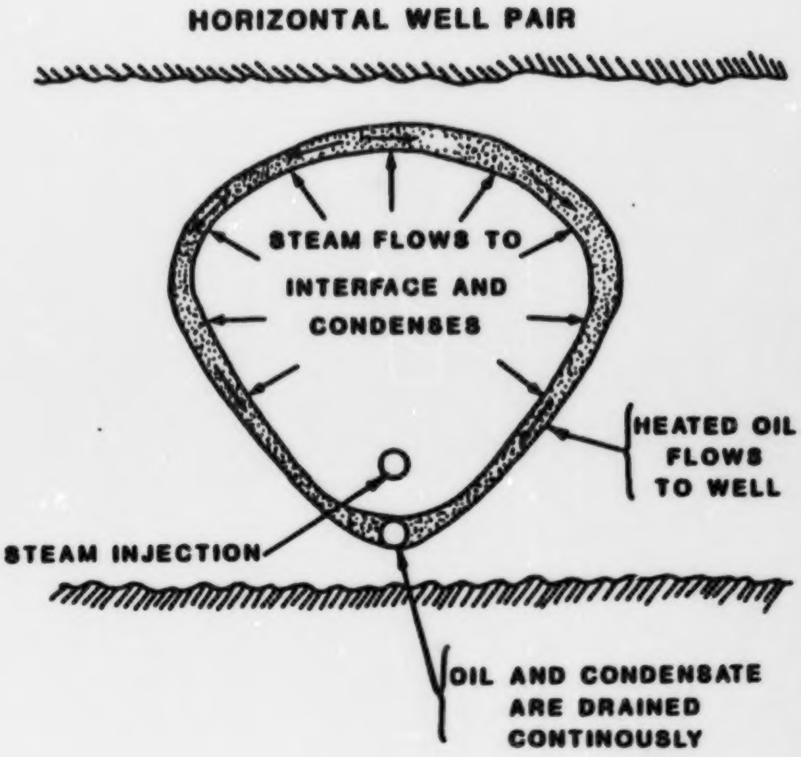

HORIZONTAL WELL PAIR
STEAM FLOWS TO INTERFACE AND CONDENSES
HEATED OIL FLOWS TO WELL
STEAM INJECTION
OIL AND CONDENSATE ARE DRAINED CONTINOUSLY

FIGURE 1. STEAM ASSISTED GRAVITY DRAINAGE CONCEPT

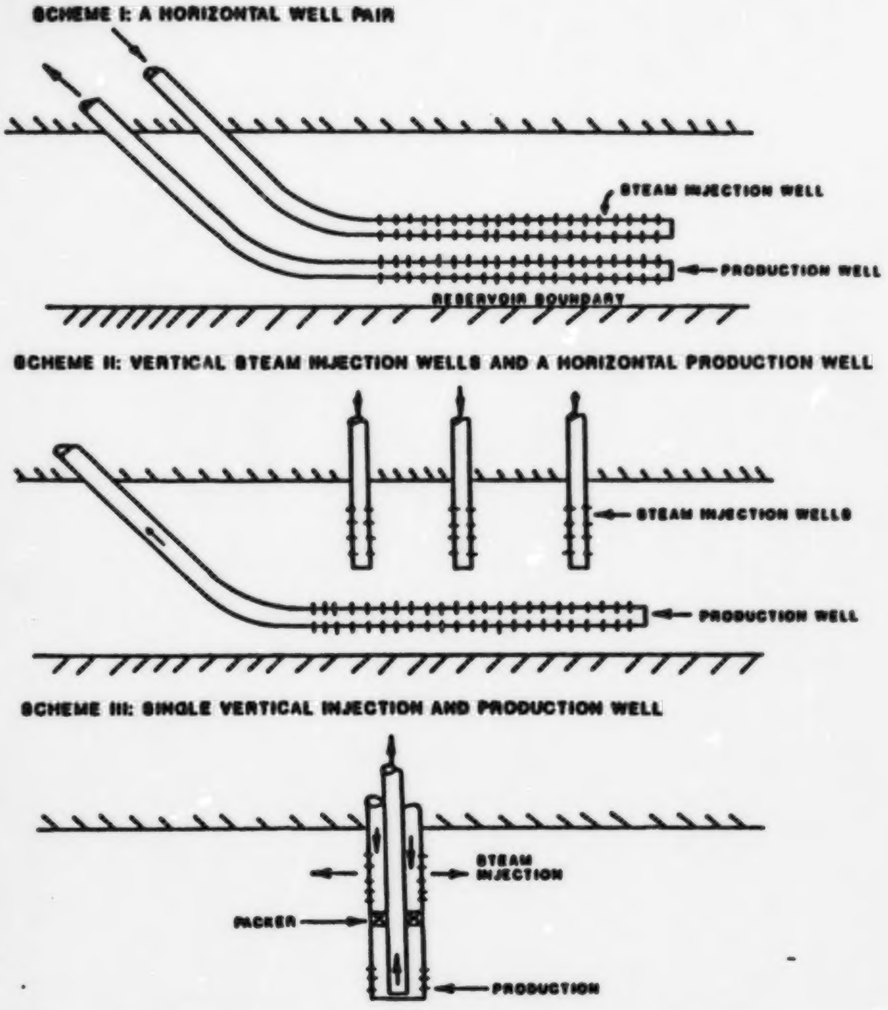

SCHEME I: A HORIZONTAL WELL PAIR
STEAM INJECTION WELL
PRODUCTION WELL
RESERVOIR BOUNDARY
SCHEME II: VERTICAL STEAM INJECTION WELLS AND A HORIZONTAL PRODUCTION WELL
STEAM INJECTION WELLS
PRODUCTION WELL
SCHEME III: SINGLE VERTICAL INJECTION AND PRODUCTION WELL
STEAM INJECTION
PACKER
PRODUCTION

FIGURE 2. WELL CONFIGURATION SCHEMES

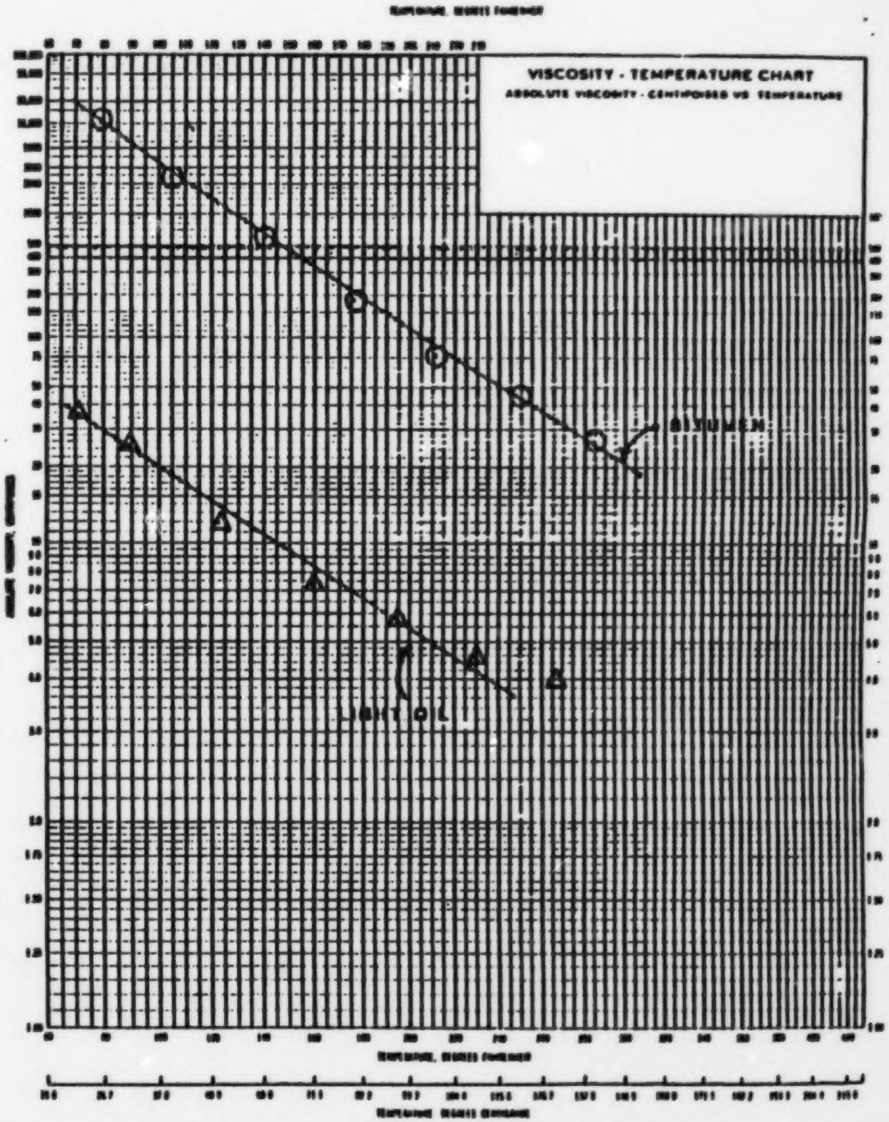


FIGURE 3. VISCOSITY OF EXPERIMENTAL FLUIDS

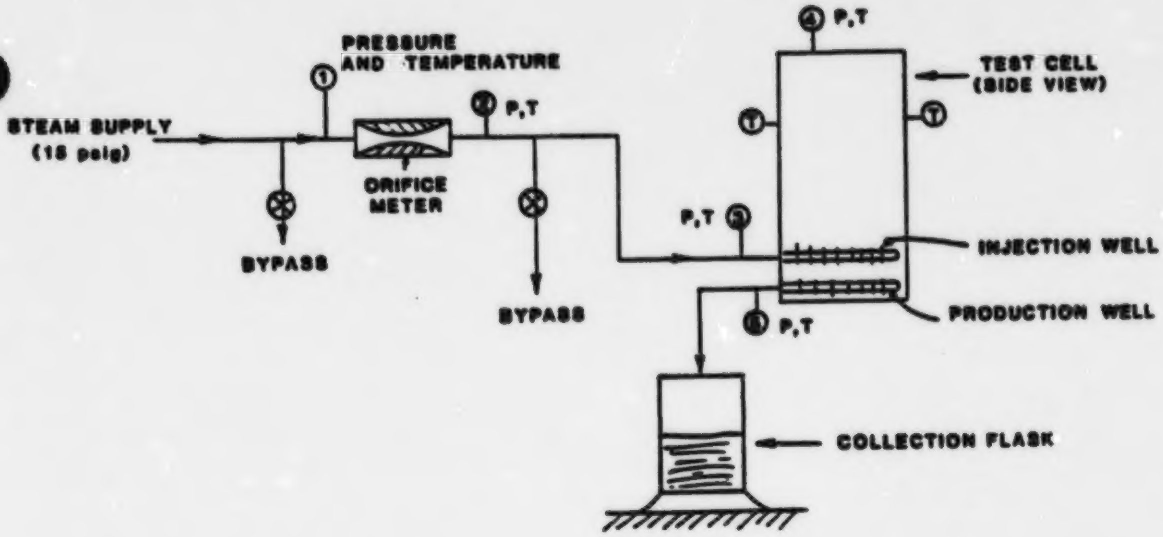


FIGURE 4. SCHEMATIC OF EXPERIMENTAL SETUP

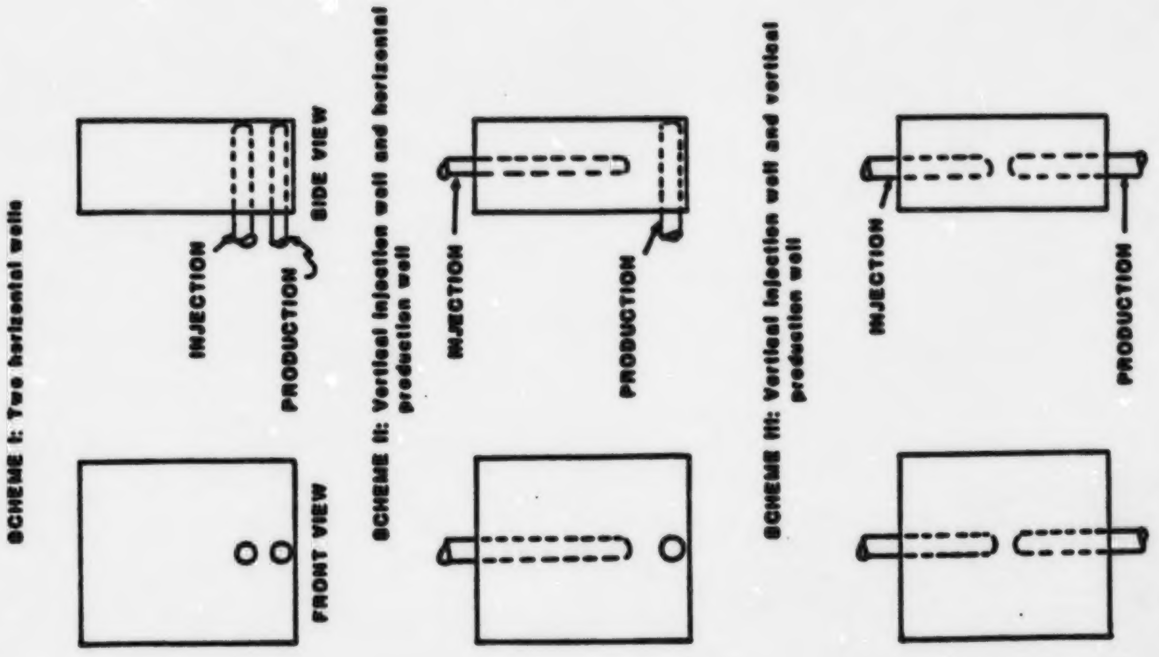
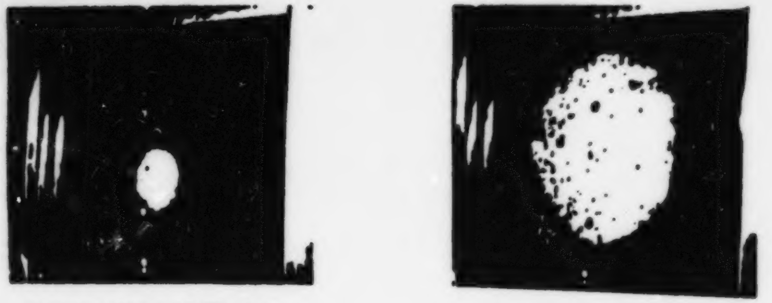
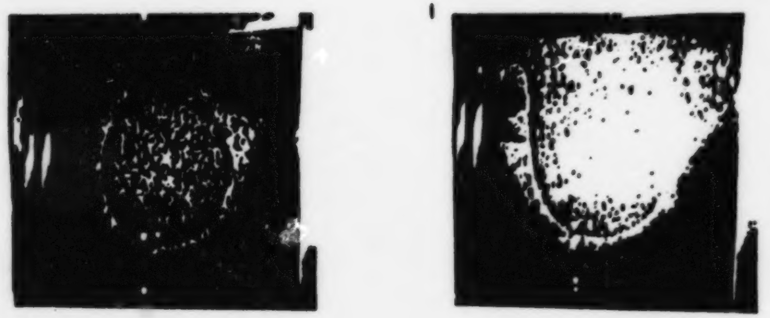

SCHEME I: Two horizontal wells
FRONT VIEW
SIDE VIEW
INJECTION
PRODUCTION
SCHEME II: Vertical injection well and horizontal production well
INJECTION
PRODUCTION
SCHEME III: Vertical injection well and vertical production well
INJECTION
PRODUCTION

FIGURE 5 EXPERIMENTAL SIMULATION OF WELL CONFIGURATION SCHEMES



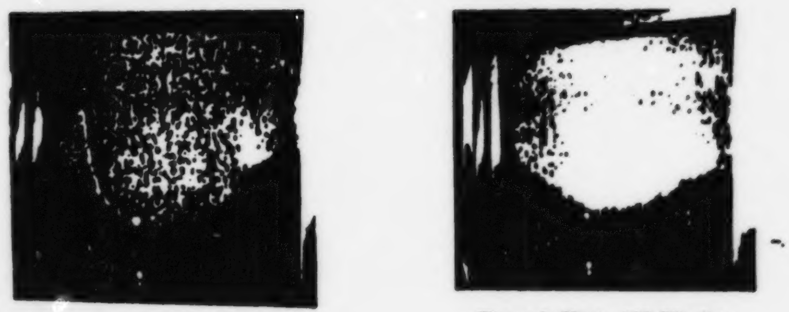
Elapsed Time: 13 Minutes

Elapsed Time: 64 Minutes



Elapsed Time: 104 Minutes

Elapsed Time: 169 Minutes



Elapsed Time: 246 Minutes

Elapsed Time: 418 Minutes

Figure 6: Typical Steam Bubble Development In A Uniform Permeability Model

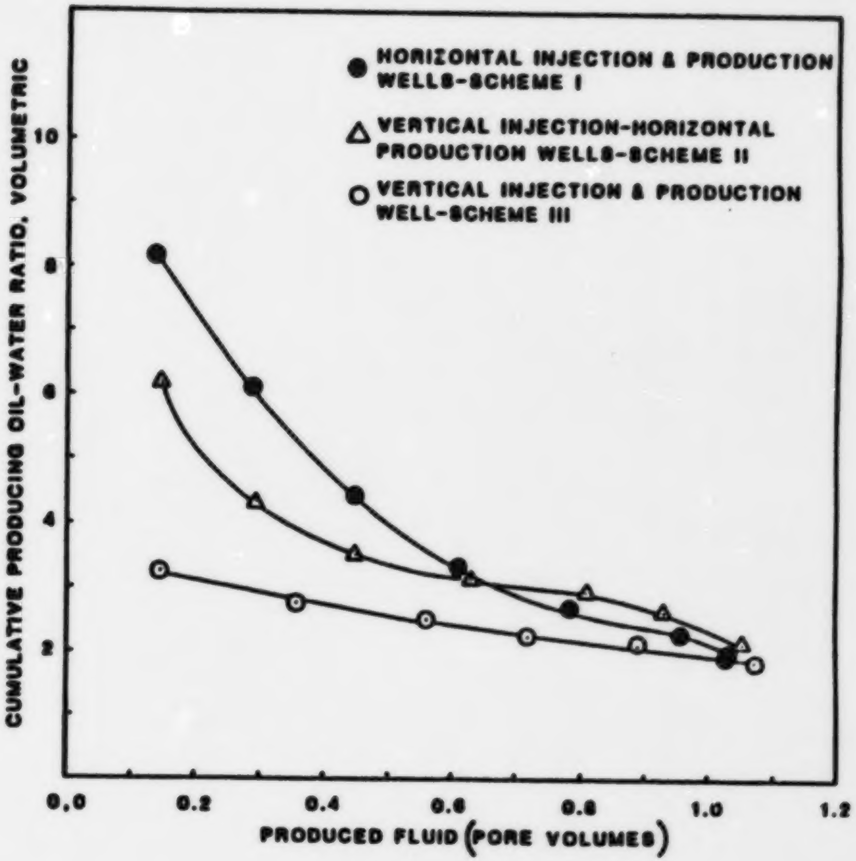


FIGURE 7. EFFECT OF PRODUCTION SCHEME ON CUMULATIVE PRODUCING OIL-WATER RATIO

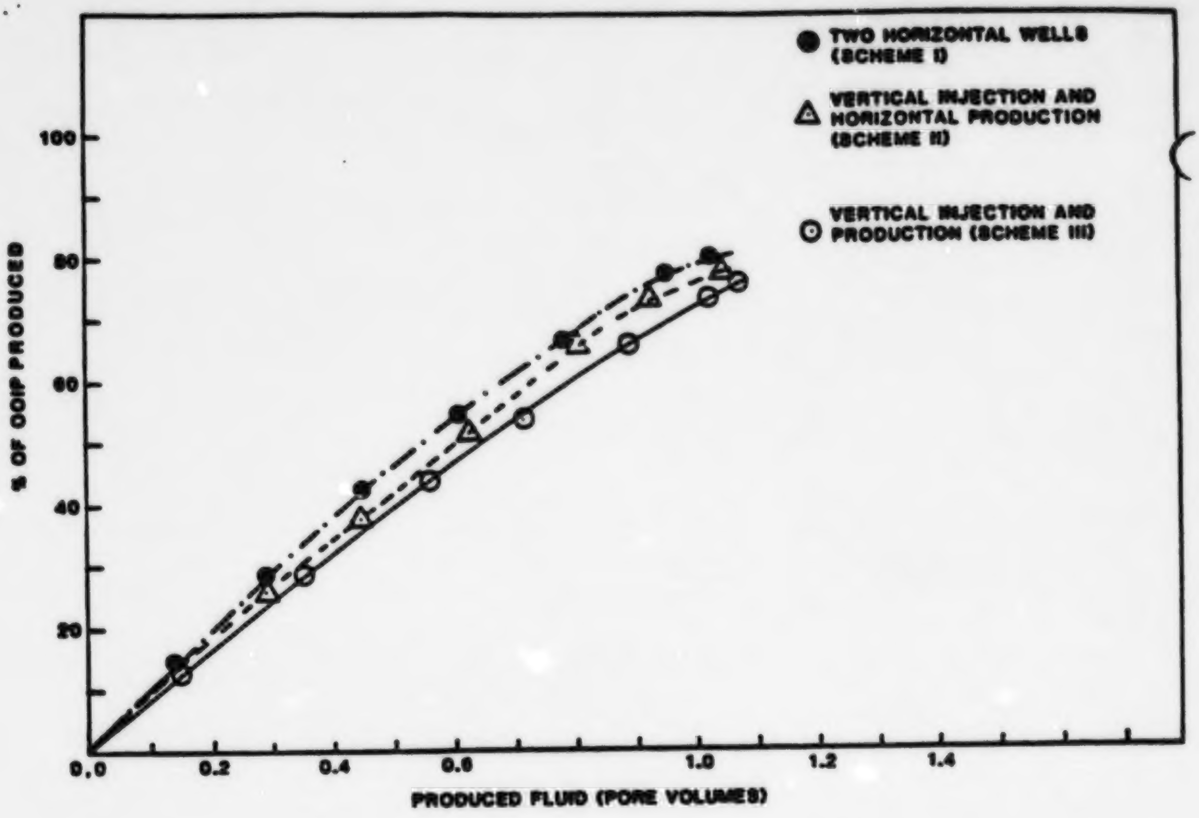
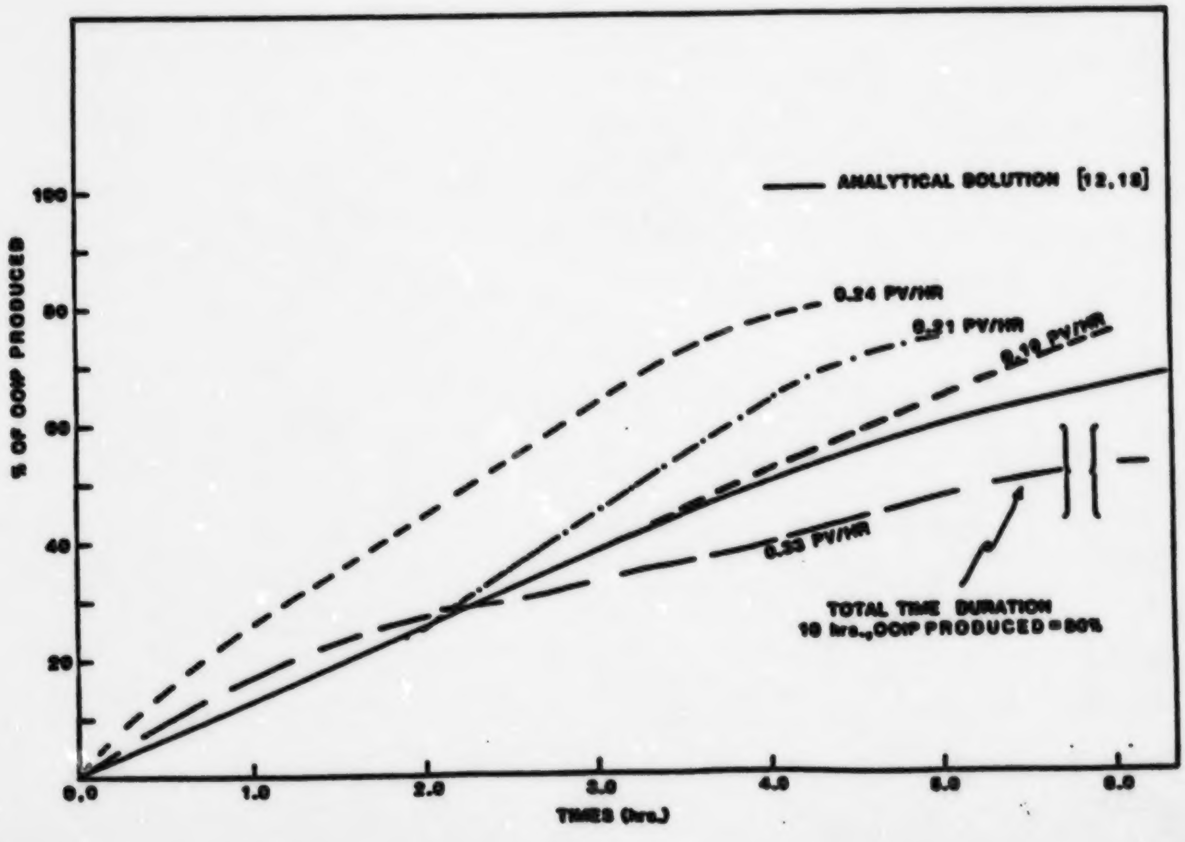


FIGURE 8. PERCENTAGE OF OOIP RECOVERED USING DIFFERENT PRODUCTION SCHEMES



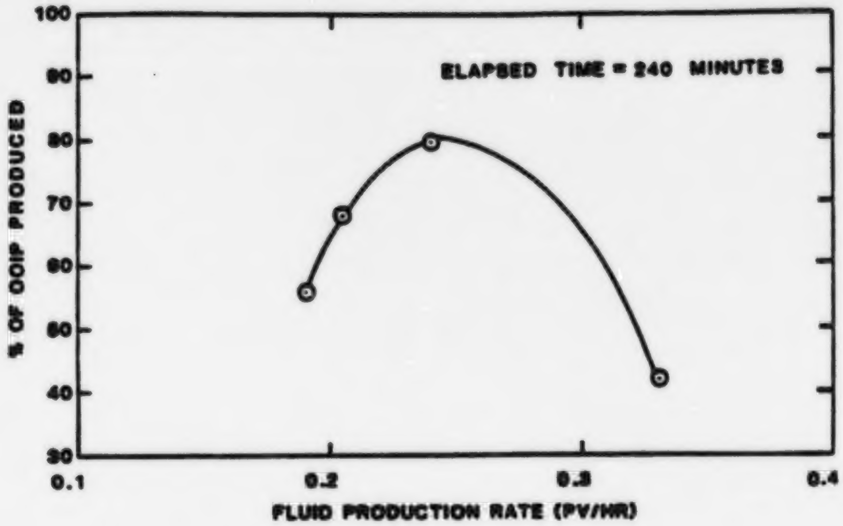


FIGURE 10. OPTIMUM FLUID PRODUCTION RATE FOR TWO HORIZONTAL WELL CONFIGURATION (SCHEME I)

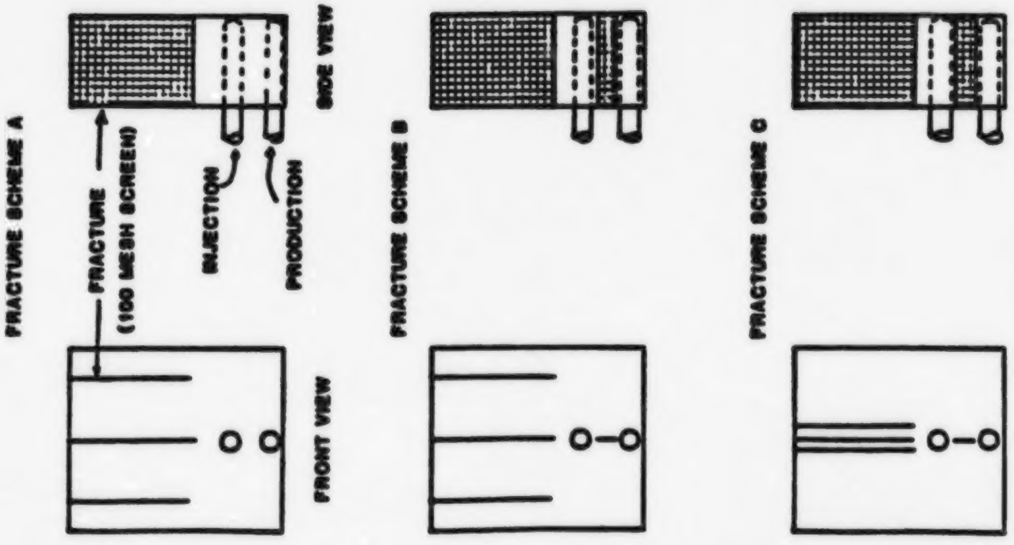
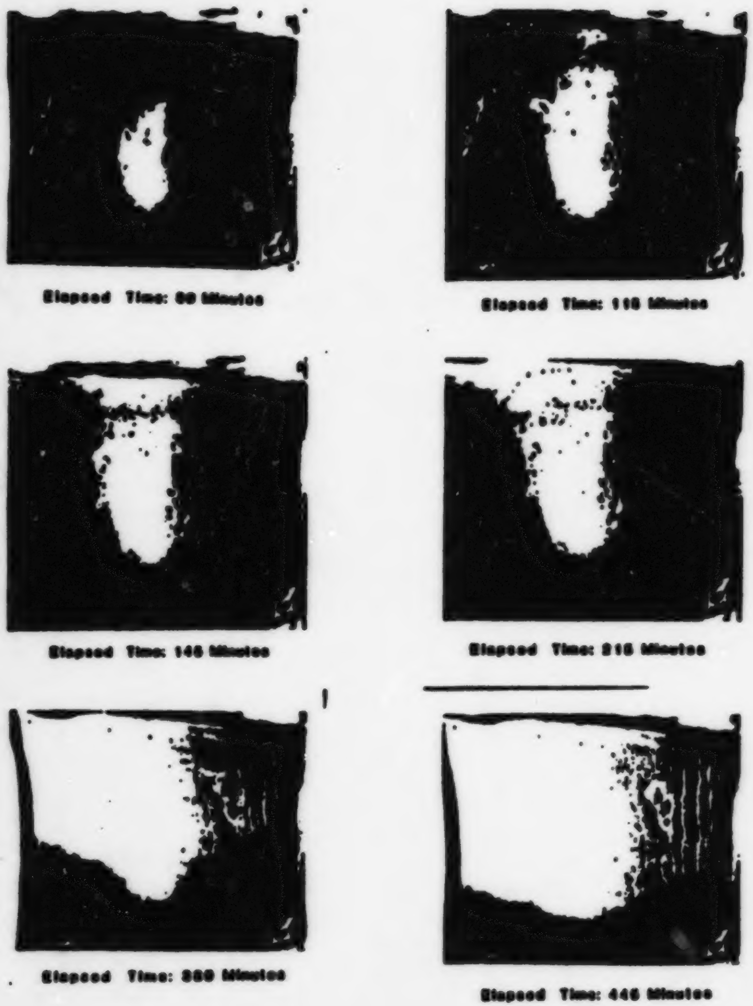


FIGURE 11. EXPERIMENTAL SIMULATION OF DIFFERENT FRACTURE DISTRIBUTION



Elapsed Time: 60 Minutes

Elapsed Time: 116 Minutes

Elapsed Time: 146 Minutes

Elapsed Time: 216 Minutes

Elapsed Time: 266 Minutes

Elapsed Time: 446 Minutes

Figure 12: Typical Steam Bubble Development In A Fractured Model

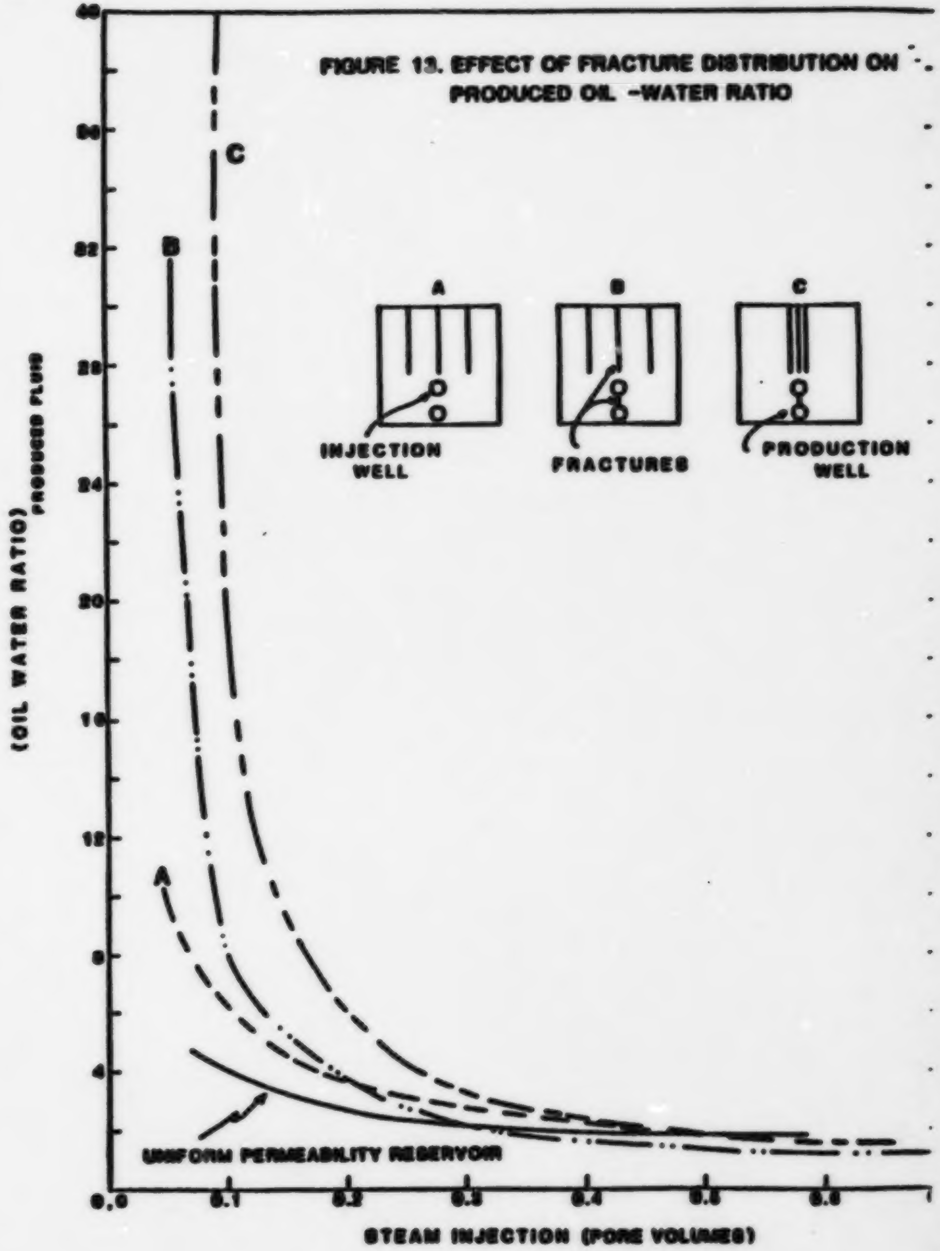


FIGURE 13. EFFECT OF FRACTURE DISTRIBUTION ON PRODUCED OIL -WATER RATIO

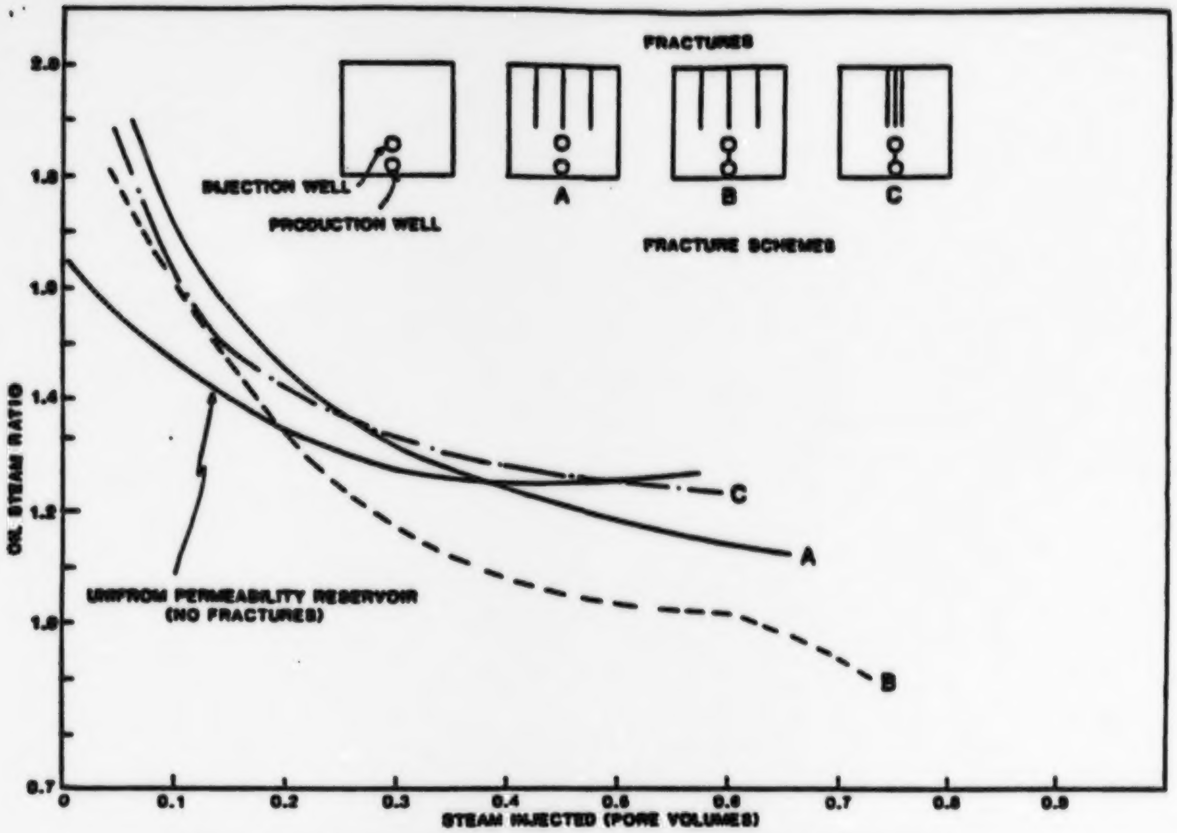


FIGURE 14. INFLUENCE OF FRACTURE DISTRIBUTION ON OIL STEAM RATIO

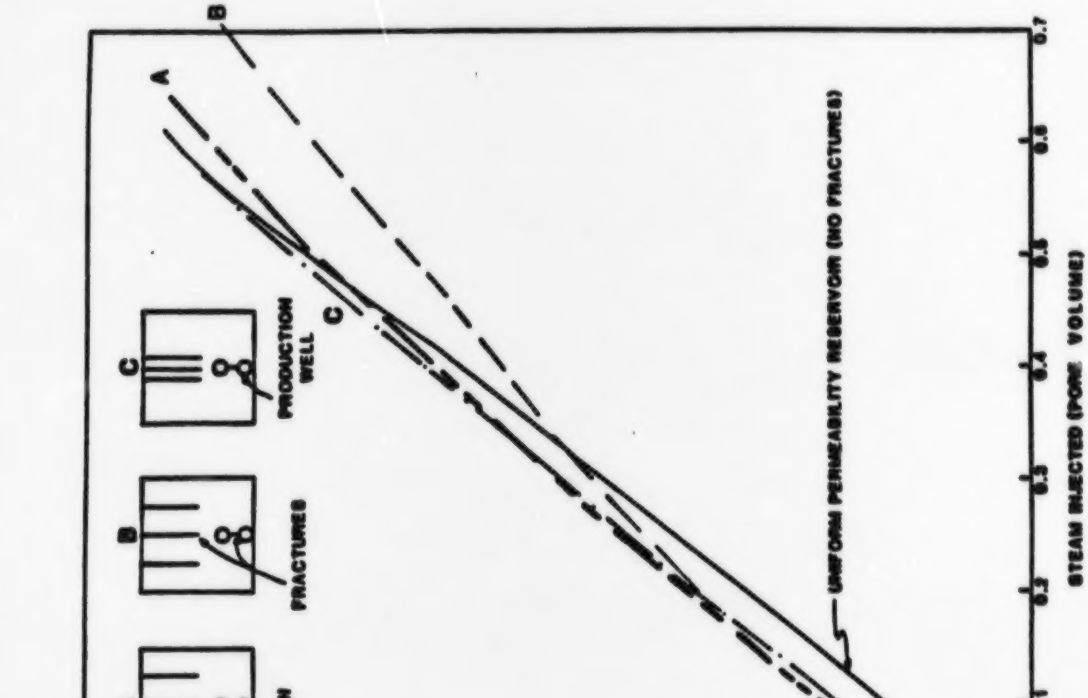


FIGURE 15. INFLUENCE OF FRACTURE DISTRIBUTION ON PERCENTAGE OF OOIP RECOVERED

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69

Augmentation of Well Productivity Using Slant and Horizontal Wells

by S.D. Joshi, *Phillips Petroleum Co.*
SPE Member

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ABSTRACT

This paper presents an equation to calculate the productivity of horizontal wells and a derivation of that equation using potential fluid flow theory. This equation may also be used to account for reservoir anisotropy and well eccentricity (i.e., horizontal well location other than mid-height of a reservoir). The theoretical predictions were used to calculate the effective well bore radius and the effective skin factors of horizontal wells. Laboratory experiments using an electrical analog were also conducted. The present laboratory experimental data and also the laboratory data available in the literature show good agreement with the theoretical equation, indicating its accuracy.

The paper also compares vertical, slant, and horizontal well productivity indices, assuming an equal drainage area. In addition, the comparison also assumes an equal reservoir contact area for slant and horizontal wells. The results show that in a 100 ft (30.48 m) thick reservoir, horizontal well productivities are 2 to 5 times greater than unstimulated vertical or slant well productivities, depending upon reservoir anisotropy. Conversely, in a 400 ft (122 m) thick reservoir, slant wells perform better than horizontal wells if vertical permeability is less than the horizontal permeability.

Horizontal wells perform significantly better than vertical wells in reservoirs with gas cap and/or bottom water. This study reports an equation to compare horizontal and vertical well gas coning tendencies.

The results indicate that horizontal wells are suitable for reservoirs which are thin, show high vertical permeability or exhibit gas and water coning problems. The equations reported in this paper should be useful in an initial evaluation of a horizontal well drilling proposal.

References and illustrations at end of paper.

INTRODUCTION

Today around the world about 30 horizontal wells are producing oil successfully[1]. The wells have been drilled in Prudhoe Bay[2], Alaska, Empire Abo Unit in New Mexico[3], France and offshore Italy.[4,5,6] Due to a large reservoir contact area, horizontal well oil production rates are 2 to 5 times greater than unstimulated vertical well rates. In addition, horizontal wells may intersect several fractures and help to drain them effectively. Horizontal wells have also been known to reduce water and gas coning tendencies. The disadvantages of horizontal wells are: 1) they are ineffective in thick (~ 500 to 600 ft, 150 to 180 m), low vertical permeability reservoirs, 2) reservoirs with several oil zones, separated by impermeable shale barriers, may require drilling of a horizontal hole in each reservoir layer to be drained, 3) presently, some limitations exist in well completion and stimulation technology, and 4) drilling costs are 1.4 to 2 times more than those for vertical wells.

OBJECTIVES

The major objective of this work is to develop necessary mathematical equations for an initial evaluation of horizontal well drilling prospects. This included the following objectives:

1) To develop a mathematical equation to calculate steady state oil production using horizontal wells.

2) To determine the influence of reservoir anisotropy, height, well drainage area, and eccentricity (well location other than the reservoir center) on horizontal well productivity.

3) To devise laboratory electrical analog experiments to measure horizontal well productivities and compare them with the theoretical equation.

$$\Omega_h + \Omega_v = \Delta P \left[\frac{1}{Q_1^*} + \frac{1}{Q_2^*}\right] = \Delta P/Q_h$$

and

$$Q_h = \frac{[2\pi\ k_o\ h\Delta P/(\mu\ B_o)]}{\ln\left[\frac{a + \sqrt{a^2 - (L/2)^2}}{L/2}\right] + \frac{h}{L}\ln\left[\frac{h}{2\ r_w}\right]}$$

for $L > h$ and $(L/2) < 0.9\ re_h$ ....(5)

Where 'a', half the major axis of a drainage ellipse in a horizontal plane in which the well is located (see Fig. 2), is obtained by reformulating Eq. (A-11) as shown below:

$$a = (L/2)\left[\frac{1}{2} + \sqrt{\frac{1}{4} + \frac{1}{(0.5\ L/re_h)^4}}\right]^{0.5} \qquad .....(6)$$

Table I lists the correspondence between $L/(2a)$ and $L/(2re_h)$ values. Equation (5) shows that if the horizontal well length significantly exceeds the reservoir height ($L/h >> 1$), then the second term in the denominator of Eq. (5), representing the vertical flow resistance, tends to be very small as compared to the first term (horizontal resistance). Moreover, if $L/(2a) << 1$, then as shown in Table I, $a \approx re_h$. Substituting this in Eq. (5) results in the following classical vertical fracture solution.[17]

$$Q = \frac{2\pi\ k_o\ h\Delta P/(\mu\ B_o)}{\ln[re_h/(L/4)]} \qquad ....(7)$$

Equation 7 will yield results identical to that given by Eq. 5 if $L/h \geq 6$. Thus, if $L/h \geq 6$, then horizontal well production can be approximated as production from a fully penetrating vertical fracture. This conclusion confirms similar findings from the transient well test solutions.[15-16] As noted earlier, this is valid only for single-phase flow. This observation is important for it provides a ready means to compare horizontal well productivity with that of stimulated wells.

Equation (5) is different from that reported in the literature.[7-12] The equation used by these authors has an additional π term in the denominator of the vertical resistance term. Since these references do not include the derivation of their equation, it was not possible to investigate the reasons for this difference. As is noted in a later part of this paper, Eq. (5) shows a fairly good agreement with the laboratory data, indicating its usefulness to predict oil production from horizontal wells.

INFLUENCE OF ANISOTROPY

In many reservoirs, the vertical permeability is less than the horizontal permeability. For a horizontal well, a decrease in vertical permeability results in an increase in vertical flow resistance and a decrease in oil production rates. Conversely, if the vertical permeability is greater than the horizontal permeability, it represents a decrease in vertical flow resistance and an increase in oil production rates. As shown by Muskat,[18] the reservoir anisotropy could be accounted for by modifying the vertical axis as $z' = h\sqrt{k_h/k_v}$ and the average reservoir permeability as $\sqrt{k_v k_h}$. Due to the modification of the z axis the well bore becomes elliptical. Assuming the ellipitcal well bore effects are negligible, Eq. (5) is modified to account for the reservoir anisotropy as shown below:

$$Q_h = \frac{[2\pi\ k_o\ h\Delta P/(\mu\ B_o)]}{\ln\left[\frac{a + \sqrt{a^2 - (L/2)^2}}{L/2}\right] + \frac{\beta h}{L}\ln\left[\frac{\beta h}{2\ r_w}\right]}$$

for $L > \beta h$ ....(8)

where $\beta = \sqrt{k_h/k_v}$

HORIZONTAL WELL ECCENTRICITY

Equations (5) and (8) assume that a horizontal well is located at the reservoir center in a vertical plane, i.e., at a distance h/2 from the reservoir top and bottom. Using Muskat's[18] formulation for off-centered wells, oil production in a vertical plane from a horizontal well placed at a distance δ from the reservoir mid-height could be shown as,

$$Q_2 = \frac{[2\pi\ k_o\ L\ \Delta P\ h/(\mu\ B_o\ h)]}{\ln\left[\frac{(h/2)^2 - \delta^2}{(h\ r_w/2)}\right]}, \text{ for } \delta < (h/2) \quad ...(9)$$

resulting in the following expressions for Ω_v and Q_h, respectively,

$$\Omega_v = \frac{\mu\ B_o\ h}{2\pi\ k_o L h}\ln\left[\frac{(h/2)^2 - \delta^2}{(h\ r_w/2)}\right] \qquad ....(10)$$

and

$$Q_h = \frac{[2\pi\ k_o\ h\Delta P\ /\ (\mu\ B_o)}{\ln\left[\frac{a + \sqrt{a^2 - (L/2)^2}}{(L/2)}\right] + \frac{h}{L}\ln\left[\frac{(h/2)^2 - \delta^2}{h\ r_w/2}\right]}$$

for $\delta < h/2$ ....(11)

A vertically centered horizontal well gives maximum productivity. The calculations demonstrate that a horizontal well located ± h/4 from the reservoir center exhibits less than a 10% reduction in maximum well productivity. This indicates that while drilling, deviations in the well location from the

4) To compare vertical, slant, and horizontal well productivities.

5) To determine gas and water coning tendencies of horizontal wells and compare them with those of vertical wells.

LITERATURE REVIEW

Borisov[7] has reported a theoretical equation to calculate steady state oil production from a horizontal well. However, the report does not include the derivation of the equation. Later, using Borisov's equation, Giger and associates[8-12] reported reservoir engineering aspects of horizontal drilling. Giger developed a concept of replacement ratio, RR, which indicates the number of vertical wells required to produce at the same rate as that of a single horizontal well.[10,11] The replacement ratio calculation assumes an equal drawdown for the horizontal and vertical wells. In addition, Giger[8] has studied fracturing of a horizontal well and has also provided a graphical solution to calculate reduction of water coning using horizontal wells.[9,11] Giger et al.[12] report that horizontal wells are suitable for thin reservoirs, fractured reservoirs, and reservoirs with gas and water coning problems.

Recently, Reiss[6] also reported a productivity index equation for horizontal wells. However, his equation is different from that reported by Borisov[7] and others.[8,11] To clarify these differences, it was decided to derive the basic steady state equation from fundamental fluid flow theory. Such a derivation is reported in this paper.

Recently, Daviau et al.[13] and others[14,15] have reported time dependent theoretical analyses for horizontal wells. Their results as well as our time dependent horizontal well theoretical results[16] (not included in this paper) indicate that if the length of a horizontal well is significantly larger than the reservoir height ($L/h >> 1$), horizontal well production is the same as that obtained from a fully penetrating vertical fracture. This is also shown by the steady state equation derived in this paper. It is important to note that implications of these results are restricted to a single phase flow.

A HORIZONTAL WELL OIL PRODUCTION EQUATION

Figure 1 shows that a horizontal well of length L drains an ellipsoid while a conventional vertical well drains a right circular cylindrical volume. Both of these wells drain a reservoir of height h, but their drainage volumes are different. Mathematically, to calculate oil production from a horizontal well, first the three dimensional Laplace equation ($\nabla^2 P=0$) needs to be solved. The Laplace solution, assuming constant pressure at the drainage boundary and at the well bore, would give a pressure distribution with a reservoir. Once the pressure distribution is known, then oil production rates can be calculated by Darcy's law.

To simplify the mathematical solution, the three dimensional problem is subdivided into two, two-dimensional problems. Figure 2 shows the following subdivision of the ellipsoid drainage problem: 1) oil flow into horizontal well in a horizontal plane, and 2) oil flow into horizontal well in a vertical plane. Appendices A and B describe mathematical solutions to these two problems using potential fluid flow theory. The solutions are added to calculate oil production from a horizontal well. As described in Appendix A, Eq. (A-8) gives oil flow to a horizontal well in a horizontal plane.

$$Q_1 = \frac{(2\pi\ k_o\ \Delta P/\mu\ B_o)}{\ln\left[\dfrac{a + \sqrt{a^2 - (L/2)^2}}{L/2}\right]} \qquad \text{......(A-8)}$$

Multiplying the above equation by reservoir height, h, gives oil production from a number of horizontal wells stacked one above the other from the reservoir bottom up to the top:

$$Q_1^* = Q_1\ h \qquad \text{.......(1)}$$

Using an electrical analog concept, flow resistance in a horizontal direction is given as

$$\Omega_h = (\Delta P/Q_1^*) = \frac{\mu\ B_o}{2\pi k_o\ h} \ln\left[\frac{a + \sqrt{a^2 - (L/2)^2}}{L/2}\right] \qquad \text{..(2)}$$

In addition to the above horizontal direction resistance, Ω_h, a horizontal well of height $2r_w$, experiences a vertical flow resistance. Equation (B-6) gives the flow into a horizontal well of a unit length, located at the reservoir center.

$$Q_2 = \frac{(2\pi\ k_o\ \Delta P/\mu\ B_o)}{\ln\{h/(2\ r_w)\}} \qquad \text{.........(B-6)}$$

Q_2^*, the oil flow to a horizontal well of length L, and Ω_v corresponding flow resistance in a vertical direction, are calculated by the following expressions, respectively:

$$Q_2^* = Q_2 L \qquad \text{...........(3)}$$

and

$$\Omega_v = (\Delta P/Q_2^*) = [\mu\ B_o/(2\pi\ k_o\ L)]\ln\{h/(2r_w)\} \qquad \text{......(4)}$$

The vertical resistance term in Eq. (4) represents resistance in a vertical plane in a circular area of radius h/2 around the well bore. Part of this resistance is already accounted for in the horizontal resistance term. As shown later in the paper, this duplication did not severely affect the accuracy of the solution.

Several different methods of combining Ω_h and Ω_v were considered to calculate effective flow resistance. The addition of Ω_h and Ω_v not only gave mathematically simple results, but also showed good agreement with the laboratory experimental data. Therefore, horizontal and vertical resistances were added to calculate horizontal well oil production as shown below:

reservoir center should not significantly affect well productivity. However, if $L/h < 2$ and/or $2\delta/h > 0.5$ then well eccentricity significantly affects well productivity. These results were also confirmed experimentally using an electrical analog, which is described later in this paper.

EFFECTIVE WELL BORE RADIUS AND SKIN FACTOR

For a given drainage area, the vertical well production rate increases with an increase in well bore radius. Hence, the higher oil production of slant and horizontal wells could also be represented by a vertical well of a large well bore diameter. In a conventional vertical well, increased well production due to well stimulation is represented as a decrease in a negative skin factor or an increase in an effective well bore diameter. The relationship between skin factor and effective well bore radius is defined as given below:

$$r_{w,eff} = r_w \exp(-s) \qquad \text{............(12)}$$

To calculate the required vertical well bore diameter to produce oil at the same rate as that from a horizontal well, the following assumptions were made: 1) equal drainage volume, $re_h = re_v$ and 2) equal productivity index, $(Q/\Delta P)_h = (Q/\Delta P)_v$. With these assumptions we have

$$\left[\frac{2\pi\, k_o\, h/(\mu\, B_o)}{\ln(re/r_{w,eff})}\right]_v =$$

$$\left[\frac{2\pi\, k_o\, h/(\mu\, B_o)}{\ln\left[\dfrac{a+\sqrt{a^2-(L/2)^2}}{(L/2)}\right]+\dfrac{h}{L}\ln\left[\dfrac{h}{2\, r_w}\right]}\right]_h \qquad \text{..(13)}$$

and

$$r_{w,eff} = \frac{re_h(L/2)}{a\left[1+\sqrt{1-(L/2a)^2}\right]\left[h/(2\, r_w)\right]^{h/L}} \qquad \text{...(14)}$$

with 'a' calculated from either Eq. (6) or Table I. Equations (14) and (12) could be used to calculate effective well bore radius, $r_{w,eff}$, and skin factor, s, respectively. The following equation yields the ratio of horizontal and vertical well productivity indices:

$$J_h/J_v = [\ln(re_v/r_w)]/[\ln(re_h/r_{w,eff})]$$

$$\text{for } L > h\sqrt{k_h/k_v} \text{ and } (L/2) < 0.9\, re_h \qquad \text{....(15)}$$

It is important to note that the above comparison assumes an *unstimulated* vertical well. Since vertical well stimulation varies from region to region, for general comparison, only unstimulated vertical well productivities are used. The productivity increases calculated from Eq. (15) will have to be adjusted depending upon local experience with the vertical well stimulation treatments. Equation (15) is valid only for reservoirs operating above the bubble point. Nevertheless, in a solution gas drive reservoir the productivity index is a first derivative of an inflow performance (IPR) curve. Therefore, in a solution gas drive reservoir also, Eq. (15) would give a fair estimation of productivity improvements using horizontal wells.

SLANT WELL PRODUCTIVITY

A horizontal well represents a limiting case of a slant well when slant angle becomes 90°. Therefore, this study includes comparisons of slant and horizontal well productivities. For a well with slant angle less than 75°, Cinco *et al.*[19] and Van Der Vlis *et al.*[20] have reported equations to calculate well productivities. Cinco *et al*. proposed an equation to calculate the skin factor due to a slant well while Van Der Vlis *et al*. proposed an equation to calculate the effective well bore radius of a slant well. The slant well productivities calculated using the equations of Cinco *et al.*[19] and Van Der Vlis *et al.*[20] were in excellent agreement. Hence, the correlation provided by either author could be used to calculate slant well productivities.

THE MEASUREMENTS OF WELL PRODUCTIVITY AUGMENTATION

The skin factor and the ratio of productivity indices measure the augmentation of well productivity for slant and horizontal wells. These parameters could be calculated using Eqs. (12), (14), and (15), and assuming an equal drainage volume for vertical, slant and horizontal wells. For horizontal wells, an additional productivity improvement measurement is the replacement ratio. This accounts for different drainage areas for horizontal and vertical wells. As noted earlier, the replacement ratio indicates the number of vertical wells that are required to produce at the same rate as that of a single horizontal well.

Giger[10] introduced the concept of areal productivity index, API, to calculate the replacement ratio, RR. This equation is modified in this work to facilitate calculation of RR. In addition, equations presented here include the influence of reservoir anisotropy, which was not included in the original work. Appendix C describes the derivation of equations to calculate RR. Equation (C-6) in Appendix C suggests that RR depends upon horizontal well drainage radius, re_h. Therefore, RR values were calculated by varying $L/(2re_h)$ from 0.1 to 0.9. This resulted in less than 7% variation in RR values; the results demonstrate that RR depends upon horizontal well length L rather than on the ratio $L/(2re_h)$. Therefore, all calculations presented in this paper assume $re_h = L$.

It is important to avoid confusion between the productivity indices ratio and the replacement ratio, RR. A productivity indices ratio assumes an equal drainage area for horizontal and vertical wells. Conversely, a replacement ratio accounts for the different drainage areas of horizontal and vertical wells.

COMPARISON OF THEORETICAL PREDICTIONS AND EXPERIMENTAL DATA

Perrine[21] and others [22,23] conducted electrical analog experiments to measure productivity improvements using horizontal drainholes. The present author has conducted similar experiments using a 46 inch (1.17 m) diameter tank which was filled with brine solution. A 1/32 inch (0.08 cm) diameter copper wire was used to simulate the well bore; a copper ring mounted along the tank periphery simulated the drainage boundary. The wire dimensions gave a scaling ratio of 23 between the experimental apparatus and field dimensions. A fixed voltage drop (6 volts) was imposed between the well bore and the copper peripheral ring. The similarity of Ohm's and Darcy's laws was used to estimate horizontal well productivity index ($Q/\Delta P$). The productivity indices were measured for different well lengths and water heights in the tank. Figures 3a and 3b show comparisons of Perrine's[21] laboratory data and the present laboratory data with the theoretical Eq. (15). As shown in the figures, theoretical predictions are about 7 to 10% lower than the experimental data. Although Eq. (15) assumes $L > h$, Fig. 3b shows that even for $L < h$, the theoretical predictions are only 8 to 10% lower than the experimental data. This indicates that Eq. (15) could also be used if $L < h$.

The conservative model predictions could be due to the overestimation of flow resistance around the well bore. As noted earlier, the vertical resistance term accounts for the flow resistance 360° around the well bore. Part of this resistance is also accounted for in a horizontal resistance term. Despite this duplication, the theoretical equation, Eq. (5), shows good agreement with the experimental data; this indicates the usefulness of the equation to predict horizontal well oil production rates.

Electrical analog experiments were also conducted to verify Eq. (11), which accounts for well eccentricity (well location other than the mid-height of a reservoir). The experimental results showed less than 10% variation with the results of Eq. (11).

RESULTS AND DISCUSSION

Well productivity enhancements due to horizontal wells were calculated for the following variables: 1) reservoir height: 25 to 400 ft (7.6 to 121.9 m); 2) horizontal well length: 100 to 2000 ft (30.5 to 610 m); 3) vertical well drainage area: 10, 20, 30, 40 and 80 acres (4.05E04, 8.09E04, 12.14E04, 16.19E04, and 32.37E04 m^2); and 4) vertical to horizontal permeability ratio: 0.1, 0.5, and 1.0.

Tables II, III, and IV list typical productivity improvements (Eq. (15)) for 10, 30, and 80 acre well spacings, respectively. These tables, based on the assumption of $re_h = re_v$, list results for various horizontal well lengths and k_v/k_h ratios. The productivity improvement results from Table II (30 acre, 12.14E04 m^2, well spacing) are plotted in Figs. 4 through 6. Figure 4 shows the influence of reservoir height on the horizontal and vertical well productivity indices ratio while Fig. 5 shows the same results plotted as negative skin factors. Figure 4 shows that a 1000 ft (304 m) long horizontal well augments unstimulated vertical well productivity by a factor of 7.1 and 2.15 for 25 ft (7.62 m) and 400 ft (121.92 m) thick reservoirs, respectively. In other words, as shown in Fig. 5, a 1000 ft (304 m) long horizontal well could be represented by a vertical well with negative skin factors of −6.43 and −4.0 for 25 ft and 400 ft thick reservoirs, respectively. In thin reservoirs, contact areas of horizontal wells are significantly larger than vertical wells ($L >> h$), resulting in substantially higher productivities. If $L/h >> 1$, the vertical flow resistance is very small as compared to the horizontal flow resistance, and therefore, vertical flow resistance can be neglected. Mathematically, the problem then reduces to flow into a fully penetrating vertical fracture. As noted earlier, this is consistent with the other theoretical predictions.[15,16]

Figure 6 shows the influence of reservoir anisotropy on the productivity augmentation using horizontal wells. As shown in the figure, the low vertical permeability significantly reduces horizontal well productivity. Conversely, the high vertical permeability enhances horizontal well productivity.

Figures 7, 8, and 9 depict typical replacement ratio plots for horizontal wells. The calculations assume $re_h = L$. As shown in Fig. 7, in a 100 ft (30.48 m) thick reservoir, a 1000 ft (304.8 m) long horizontal well replaces 4.2 and 3.1 conventional vertical wells drilled at 10 and 80 acre (4.05E04 and 32.37E04 m^2) spacing, respectively. Figure 8 depicts the influence of reservoir height on the replacement ratio. A horizontal well replaces more vertical wells in a thin bed reservoir than in a thick bed reservoir, demonstrating the effectiveness of horizontal wells in thin bed reservoirs. Figure 9 shows the typical influence of reservoir anisotropy on the replacement ratios.

Figure 10 depicts the influence of reservoir height on slant well productivity. The figure shows that in an isotropic reservoir, a minimum of 35° slant is required to realize 20% productivity improvements. These requirements increase as the ratio of vertical and horizontal permeability decreases.[19,20] In contrast to horizontal wells, slant wells are more productive in thick reservoirs than in thin reservoirs. Hence, depending upon reservoir thickness and anisotropy, one should be able to maximize oil production by selecting between vertical, slant, and horizontal wells. Figures 11 and 12 show productivity comparisons of the three well geometries for 100 and 400 ft (30.48 and 121.92 m) thick reservoirs. The comparisons were made for a 30 acre (12.14E04 m^2) drainage area and for an equal reservoir contact area for horizontal and slant wells. The slant wells were assumed to give complete reservoir penetration. Figure 11 demonstrates that in a 100 ft (30.48 m) thick reservoir, a horizontal well gives better productivity than either a slant or a vertical well if $k_v/k_h \geq 0.1$. Conversely, Fig. 12 shows that in a 400 ft (121.92 m) thick reservoir, the horizontal and slant well productivities are almost equal for $k_v/k_h =$

1.0. However, for $k_v/k_h < 1$, a slant well performs better than a horizontal well.

In conclusion, horizontal wells are suitable for thin reservoirs (200 ft, 61 m) and in high vertical permeability reservoirs ($k_v = k_h$). Slant wells are suitable for thick reservoirs or in reservoirs with several impermeable shale streaks.

GAS AND WATER CONING CHARACTERISTICS

The field experience[2-6] indicates that horizontal wells not only increase oil production but they also reduce gas and water coning tendencies. Figure 13 and 14 show schematic gas and water coning diagrams for horizontal and vertical wells. A horizontal well exhibits better performance than vertical wells in resisting gas and water coning because: 1) it requires much smaller pressure drawdown than a vertical well to produce oil at the same rate, and 2) it has almost a linear pressure gradient from the well bore to the drainage radius.[9] This results in a steady gas dipping or water rise over the long producing horizontal well length. In contrast, in a vertical well, a log-linear pressure gradient from well bore to drainage radius along with a conical flow at a single point (see Fig. 14) accelerates coning problems. As noted earlier, Giger[9,11] has developed a chart to calculate water coning for horizontal wells. Another method, probably simpler, is described below. The following equation calculates production without gas coning from a vertical well.[24]

$$(Q_{max})\ \frac{bbl}{D} = \frac{1.535(\rho_o - \rho_g)k_o[h - (h-D)^2]}{\ln(re/r_w)} \quad \ldots\ldots(16)$$

where h represents reservoir height, and D represents the distance between the gas-oil interface and the perforation top. Q_{max} represents maximum oil production without gas coning. To calculate Q_{max} for a horizontal well, we can substitute horizontal well effective well bore radius, $r_{w,eff}$ instead of r_w, in the above equation. Thus, substituting Eq. (14) into Eq. (16), assuming $re_v = re_h$, and taking a ratio of maximum oil production using horizontal and vertical wells we have,

$$\frac{[Q_{max}]_h}{[Q_{max}]_v} = \frac{[h^2 - (h - D')^2]\ \ln(re/r_w)}{[h^2 - (h - D)^2]\ \ln(re/r_{w,eff})} \quad \ldots\ldots(17)$$

where D' represents distance between the horizontal well and the gas-oil interface (see Fig. 13). Horizontal wells provide the following two operational options:

1. Drill the horizontal well at the top of the vertical well perforations, i.e., D' = D. Substituting this in Eq. (17) we have

$$\frac{[Q_{max}]_h}{[Q_{max}]_v} = \frac{\ln(re/r_w)}{\ln(re/r_{w,eff})} \quad \ldots\ldots\ldots\ldots\ldots\ldots(18)$$

Since $r_{w,eff}$ of a horizontal well is always greater than r_w of a vertical well, we always have the following relationship:

$$[Q_{max}]_h > [Q_{max}]_v \quad \ldots\ldots\ldots\ldots\ldots\ldots(19)$$

Thus, without gas coning, a horizontal well produces oil at a rate higher than a vertical well even though both are perforated at the same distance from the gas-oil interface.

2. Produce horizontal well at the same rate as the vertical well, i.e., $(Q_{max})_h = (Q_{max})_v$. Using Eq. (17) we have

$$(h - D')^2 = h^2 - \frac{(h^2 - (h - D)^2)\ \ln(re/r_{w,eff})}{\ln(re/r_w)}$$

$$\ldots\ldots\ldots\ldots\ldots\ldots(20)$$

Solving Eq. (20) we obtain D' < D. Thus, to produce at the same rate as a vertical well, a horizontal well could be located closer to the gas-oil interface than the top of the vertical well perforations. Although a horizontal well location is closer to the gas-oil interface than a vertical well, it still resists gas coning.

Since option 1 gives higher production rates than option 2, it is the preferred operational choice. A similar analysis could be made for the water coning problem.

CONCLUSIONS

The following conclusions were drawn from the present study:

1. The paper presents the derivation of mathematical equations, Eqs. (5) and (8), to calculate steady state oil production from a horizontal well. The equations include the influence of reservoir anisotropy. In addition, Eq. (11) is also given to account for a change in oil production rate due to well placement in a plane other than at the mid-height of a reservoir.

2. The theoretical predictions show good agreement with the present electrical analog experimental data and the laboratory data available in the literature.

3. A horizontal well could produce oil at a rate two to six time greater than an unstimulated vertical well, assuming the same pressure drawdown. The well productivity improvements depend upon reservoir height, horizontal well length, and reservoir anisotropy.

4. A slant well with a 60° to 70° angle to a vertical through the pay zone produces oil at a rate 2 to 3 times faster than a vertical well, under the similar pressure drawdown conditions. A minimum slant of 35° is required to increase oil production by at least 1.2 times that of a vertical well.

5. Vertical, slant and horizontal wells were compared assuming an equal drainage area. In addition, the reservoir contact area of horizontal and slant wells was assumed to be the same. The comparison shows that in a thick (400 ft, 121.9 m) reservoir, slant and horizontal well production rates are comparable if $k_v/k_h = 1$. However, if $k_v/k_h < 1$, slant wells perform better than horizontal and vertical wells. In a thin (100 ft, 30.5 m) reservoir, horizontal well production rates are significantly better than slant and vertical wells if $k_v/k_h \geq 0.1$.

6. Horizontal wells reduce gas and water coning tendencies. Equations are described in this paper to estimate the reduction in gas and water coning using horizontal wells.

7. Horizontal wells are suitable for thin reservoirs, high vertical permeability reservoirs, and reservoirs with gas and water coning problems.

NOMENCLATURE

a	half the major axis of a drainage ellipse, (feet)
A	drainage area, (acre)
B	formation volume factor (dimensionless)
c	half the horizontal well length, (feet)
D	distance between gas-oil interface and top of the vertical well perforations, (feet)
D'	distance between gas-oil interface and horizontal well, (feet)
h	reservoir height, (feet)
i	complex number variable
J	productivity index, (bbl/day/psi)
k	permeability, (Darcy)
L	horizontal or slant well length, (feet)
N	number of wells
P	pressure, (psia)
Q	flow rate, (liquid volume units/D)
Q_1	flow rate defined in Eq. (A-8)
Q_2	flow rate defined in Eq. (B-6)
Q_1^*	flow rate defined in Eq. (1)
Q_2^*	flow rate defined in Eq. (3)
Q_h	flow rate into horizontal well
r	radius (feet)
re	drainage radius, (feet)
r_w	well bore radius, (feet)
$r_{v,eff}$	effective vertical well bore radius, (feet)
RR	replacement ratio
s	skin factor (dimensionless)
z	distance along vertical axis, (feet)

Greek Symbols

α	slant angle with the vertical axis, (degrees)
β	square root of the permeability ratio $\sqrt{k_h/k_v}$
δ	vertical distance between the reservoir center and the horizontal well location, (feet)
ΔP	pressure drop, (psia)
θ	coordinate in the cylindrical coordinate system, (degrees)
μ	fluid viscosity, (cp)
ρ	density, (gm/cm)
ϕ	potential function
ψ	stream function
Ω	flow resistance

Subscripts

g	gas
h	horizontal well
o	oil
v	vertical well

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APPENDIX A

Calculation of Flow in a Horizontal Plane

Figure 15a shows a schematic diagram of flow to a horizontal well in a horizontal plane. The ellipses represent constant pressure (constant ϕ) curves while the hyperbolas represent constant flow velocity lines (constant ψ). Slichter[25] has shown that such a system of confocal ellipses and hyperbolas could be represented as

$$w(z) = \phi + i\psi = \cosh^{-1}(z/c) \qquad \text{............(A-1)}$$

by definition $z = x + iy$. Substituting this into Eq. (A-1), and then equating real and imaginary parts we have

$$x = c \cosh\phi \cos\psi \qquad \text{..................(A-2)}$$

$$y = c \sinh\phi \sin\psi \qquad \text{..................(A-3)}$$

Equations (A-2) and (A-3) could be rewritten in terms of hyperbolic and trigonometric functions. The equation with the hyperbolic function represents a classical equation of an ellipse while the equation with the trigonometric functions represents a classical equation of a hyperbola. Equation (A-2) and (A-3) could be reformulated as

$$\phi = \cosh^{-1} H^* \quad \text{......................(A-4)}$$

$$\psi = \cos^{-1} H^* \quad \text{........................(A-5)}$$

where

$$H^* = \left[\frac{x^2 + y^2 + c^2 \pm \sqrt{(x^2 + y^2 + c^2)^2 - 4c^2x^2}}{2c^2}\right]^{1/2}$$

The plus sign refers to ϕ and the minus sign refers to ψ. Boundary conditions for the horizontal well located along the x axis are:

$\phi = 0$, for $|x| \leq c$ i.e., $P_{well} = 0$

$\phi = \cosh^{-1} \left|\frac{a(x,y)}{c}\right|$, for $|x| \geq c$; reservoir pressure

$\psi = \cos^{-1} \left|\frac{a(x,y)}{c}\right|$, for $|x| < c$; well bore flow

$\psi = 0$, for $x > c$

$\psi = \pi$, for $x < -c$

The potential function ϕ is the same as pressure P. At drainage radius, re_h, half the major and minor axes of the ellipse of constant pressure are a and b (see Fig. 2). Hence, pressure at the drainage boundary, P_e, is

$$P_e = \cosh^{-1} (a/c) = \ln \frac{(a + \sqrt{a^2-c^2})}{c} \quad \text{......(A-7)}$$

ΔP, the pressure drop between the drainage boundary and well is the same as P_e, defined in Eq. (A-7), since well bore pressure is assumed to be zero. Substituting this into Darcy's porous medium equation we can show it to be[25]

$$Q_1 = \frac{2\pi \; k_o \; \Delta P/\mu}{\ln \left[\frac{a + \sqrt{a^2-c^2}}{c}\right]} \quad \text{.............(A-8)}$$

where c = half well length = L/2. The above equation represents flow to a horizontal well from a horizontal plane.

In calculations, we normally use drainage radius. To calculate horizontal well drainage radius, re_h, areas of a circle and ellipse (in a horizontal plane, Fig. 15a) are equated. This reduces to

$$re_h = \sqrt{ab} \quad \text{.................(A-9)}$$

where a and b are major and minor axes of a drainage ellipse. Moreoever, +L/2 and -L/2 represent focci of a drainage ellipse. Hence, using properties of an ellipse we can show that

$$b = \sqrt{a^2-(L/2)^2} \quad \text{...................(A-10)}$$

Substituting Eq. (A-10) into Eq. (A-9) we have

$$re_h = a\left[1 - (L/2a)^2\right]^{1/4} \quad \text{.............(A-11)}$$

Equation (A-11) shows that if $L/2a \leq 0.5$, $re_h = a$. Table I lists the geometrical relationship between L, re_h, and a.

APPENDIX B

Calculation of Flow in a Vertical Plane

As shown in Fig. 15b, a horizontal well is represented as a sink in a parallel plate channel. Hence, using the Schwarz-Christoffer mapping function[26] we can show that

$$w(z) = \phi + i\psi = -q \ln \sinh (\pi z/h) \quad \text{...........(B-1)}$$

where -q represents sink strength, i.e., flow rate per unit length of a horizontal well. The right hand side of Eq. (B-1) is split into real and imaginary parts, and these parts are then equated with ϕ and ψ, respectively. To achieve this, term $\sinh(\pi z/h)$ is first rewritten in its exponential form. The exponential terms are then expanded as a power series. Neglecting high order series terms it reduces to the following:

$$\phi + i\psi = q\left[(\pi z/h) - \ln(\pi a/h)\right] \quad \text{...........(B-2)}$$

By definition, $z = r\mathrm{Exp}(i\theta)$

Substituting Eq. (B-2) into (B-1) and expanding $\mathrm{Exp}(i\theta)$ in terms of $\sin\theta$ and $\cos\theta$ we can show that

$$\phi + i\psi = q\left[(\pi r/h)\cos\theta - \ln(\pi r/h)\right]$$
$$+ iq\left[(\pi r/h)\sin\theta - \theta\right] \quad \text{................(B-3)}$$

The real part of Eq. (B-3) represents potential function (pressure function) ϕ and the complex part represents stream function (flow rate) ψ.

At the channel wall, $r = h/2$ and $= 90°$. Here the function calculated from Eq. (B-3) has zero value indicating no flow across the reservoir boundary. Similarly, the channel wall boundary conditions are substituted into the real part of Eq. (B-3) to obtain pressure at the wall. The pressure at the well bore is assumed constant. Hence, by substituting $r = r_w$ and $= 90°$ in the real part of Eq. (B-3) we can obtain pressure at the well bore. ΔP, the pressure difference between the channel wall and the well bore can be shown to be

$$\Delta P = -q \ln (h/2r_w) \quad \text{.......................(B-4)}$$

Darcy's equation for flow through a porous medium is

$$Q_{well} = Q_2 = \int_0^{2\pi} (-qk/\mu)d\phi \quad \text{............(B-5)}$$

Substituting q from Eq. (B-4) into (B-5) and integrating this reduces to

$$Q_2 = \frac{(2\pi\ k_o\ \Delta P/\mu)}{\ln(h/2r_w)} \quad \text{...................(B-6)}$$

Equation (B-6) represents flow in a vertical plane to a horizontal well of unit length.

APPENDIX C

Calculation of Replacement Ratio

The replacement ratio, RR, represents the number of vertical wells required to produce at the same rate as that of a single horizontal well. The replacement ratio takes into account the differences in drainage areas of horizontal and vertical wells.

Assume it is desired to drain a reservoir with area A. Let N_v and N_h represent the number of vertical and horizontal wells required to drain area A, respectively. If A_v and A_h represent vertical and horizontal well drainage areas respectively, then

$$A = N_vA_v = N_hA_h = N_v\pi(re_v)^2 = N_h(\pi re_h)^2 \quad \text{.......(C-1)}$$

Replacement ratio, RR, is defined as

$$RR = N_v/N_h = (re_h/re_v)^2 \quad \text{..................(C-2)}$$

Giger[10,11] introduced the concept of areal productivity index, API, defined below with units bbl/day/psi/ft:

$$API = J/\text{drainage area} \quad \text{..................(C-3)}$$

Assuming equal API for the vertical and the horizontal well we have

$$\left[\frac{2\pi\ k_o\ h/\mu_o}{B_o\ \ln(re_v/r_w)re_v^2}\right]_v = \left[\frac{2\pi\ k_o\ h/\mu_o}{B_o\ \ln(re_h/r_{w,eff})re_h^2}\right]_h$$

This reduces to

$$(re_h/re_{w,eff})^{re_h^2/re_v^2} = re_v/r_w \quad \text{...............(C-4)}$$

Combining Eqs. (C-2) and (C-4) we have

$$r_{w,eff} = \sqrt{RR}\ r_w[r_w/re_v]^{(1/RR) - 1} \quad \text{..............(C-5)}$$

Equation (14) for calculating $r_{w,eff}$ of a horizontal well could be reformulated to include reservoir anisotropy as shown below:

$$r_{w,eff} = \frac{(\frac{L}{2re_h})\ (\frac{2r_w}{\beta h})^{\beta h/L}}{a\left[1 + \sqrt{1 - \frac{1}{RR}\ [(\frac{L}{2a})(\frac{re_h}{re_v})]^2}\right]} \quad \text{....(C-6)}$$

The replacement ratio, RR, is calculated by solving equation (C-5) and (C-6) simultaneously. The solution procedure involves the following:

1) Known: reservoir height, h, vertical well bore radius, r_w (0.3048 ft), vertical well drainage area, re_v, and permeability ratio, β.

2) Choose: horizontal well length, L, and select horizontal well drainage radius, re_h, so that $L/(2re_h)$ will be between 0.1 and 0.9.

3) Try different RR values (RR > 1) until for a given RR, $r_{w,eff}$ values calculated using Eqs. (C-5) and (C-6) are equal.

Newton's mid-point numerical method was used to calculate the appropriate RR values. The appropriate RR values gave less than one percent difference in calculated $r_{w,eff}$ using Eqs. (C-5) and (C-6).

Calculations show variation in the RR when $L/2re_h$ changes from 0.1 to 0.9. $L/2re_h = 0.1$ calculates the highest value of RR, while $L/2re_h = 0.9$ calculates the lowest value of RR. However, the difference between these two values is normally less than 7%, and hence, all calculations assume $L/2re_h = 0.5$.

TABLE I

Relationship Between Various Geometrical Factors

$\frac{L}{2re_h}$	$\frac{L}{2a}$	$\frac{a}{re_h}$
0.1	0.0998	1.002
0.2	0.198	1.010
0.3	0.293	1.024
0.4	0.384	1.042
0.5	0.470	1.064
0.6	0.549	1.093
0.7	0.620	1.129
0.8	0.683	1.171
0.9	0.739	1.218

TABLE II

Productivity Indices Ratios of Horizontal and Vertical Wells:

10 Acre Well Spacing*

	J_h/J_v		
L(ft)	$(k_v/k_h)=0.1$	$(k_v/k_h)=0.5$	$(k_v/k_h)=1.0$
h=25 ft (7.6m)			
100	1.08	1.70	1.93
200	1.79	2.57	2.83
400	3.09	4.17	4.50
500	3.77	5.05	5.44
650	4.89	6.55	7.05
h=50 ft (15.21 m)			
100	-	1.17	1.44
200	1.11	1.91	2.26
400	2.01	3.26	3.75
500	2.48	3.97	4.56
650	3.22	5.16	5.91
h=100 ft (30.48 m)			
200	-	1.21	1.55
400	1.13	2.18	2.72
500	1.40	2.68	3.33
650	1.82	3.48	4.32
h=200 ft (61.0 m)			
400	-	1.25	1.68
500	-	1.55	2.07
650	-	2.01	2.69
h=400 ft (121.9 m)			
500	-	-	1.13
650	-	1.04	1.47

*$(L/2) < 0.9\ re_h$ and $L > h\sqrt{k_h/k_v}$ are assumed

TABLE III

Productivity Indices Ratios of Horizontal and Vertical Wells:

30 Acre Well Spacing*

	J_h/J_v		
L(ft)	$(k_v/k_h)=0.1$	$(k_v/k_h)=0.5$	$(k_v/k_h)=1.0$
h=25 ft (7.6m)			
100	1.08	1.62	1.81
200	1.70	2.31	2.49
400	2.68	3.39	3.59
800	4.56	5.55	5.82
1000	5.63	6.82	7.14
1150	6.51	7.91	8.28
h=50 ft (15.21 m)			
100	-	1.15	1.39
200	1.10	1.79	2.07
400	1.87	2.80	3.13
800	3.34	4.73	5.19
1000	4.13	5.83	6.39
1150	4.77	6.75	7.40
h=100 ft (30.48 m)			
200	-	1.19	1.49
400	1.12	2.01	2.42
800	2.09	3.55	4.18
1000	2.60	4.39	5.15
1150	3.00	5.07	5.96
h=200 ft (61.0 m)			
400	-	1.23	1.60
600	-	1.75	2.24
800	1.15	2.28	2.90
1000	1.43	2.83	3.59
1150	1.64	3.26	4.15
h=400 ft (121.9 m)			
600	-	-	1.32
800	-	1.27	1.73
1000	-	1.58	2.15
1150	-	1.82	2.48

*$(L/2) < 0.9\, re_h$ and $L > h\sqrt{k_h/k_v}$ are assumed

TABLE IV

Productivity Indices Ratios of Horizontal and Vertical Wells:

80 Acre Well Spacing*

	J_h/J_v		
L(ft)	$(k_v/k_h)=0.1$	$(k_v/k_h)=0.5$	$(k_v/k_h)=1.0$
h=25 ft (7.6m)			
100	1.07	1.56	1.72
200	1.63	2.13	2.28
400	2.43	2.95	3.09
800	3.75	4.35	4.50
1000	4.40	5.05	5.21
1500	6.19	7.04	7.25
1900	7.88	8.97	9.24
h=50 ft (15.21 m)			
100	-	1.14	1.36
200	1.09	1.71	1.94
400	2.08	2.52	2.76
800	2.92	3.86	4.14
1000	3.48	4.52	4.83
1500	4.96	6.34	6.74
1900	6.31	8.08	8.60
h=100 ft (30.48 m)			
200	-	1.18	1.45
400	1.11	1.89	2.22
800	1.96	3.07	3.50
1000	2.37	3.65	4.12
1500	3.43	5.18	5.82
1900	4.36	6.60	7.41
h=200 ft (61.0 m)			
400	-	1.21	1.54
800	1.14	2.11	2.60
1000	1.39	2.55	3.11
1500	2.05	3.68	4.45
1900	2.60	4.68	5.66
h=400 ft (121.9 m)			
800	-	1.25	1.65
1000	-	1.53	2.01
1500	-	2.24	2.93
1900	-	2.85	3.72

*$(L/2) < 0.9\, re_h$ and $L > h\sqrt{k_h/k_v}$ are assumed

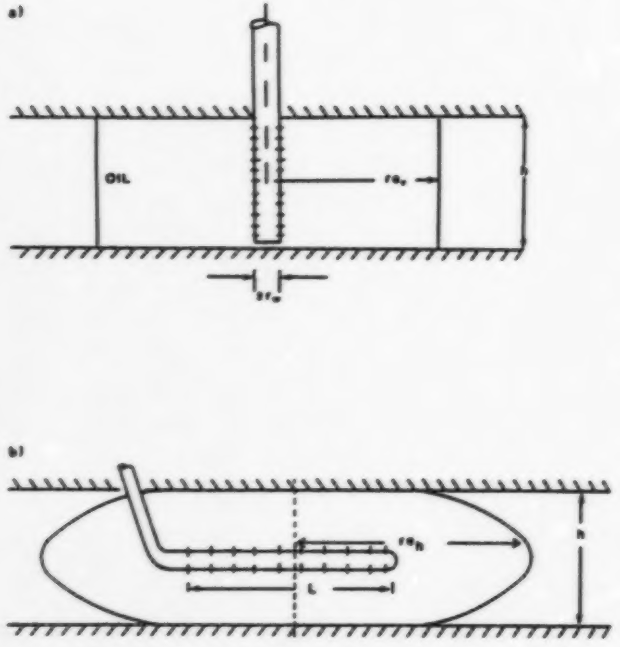
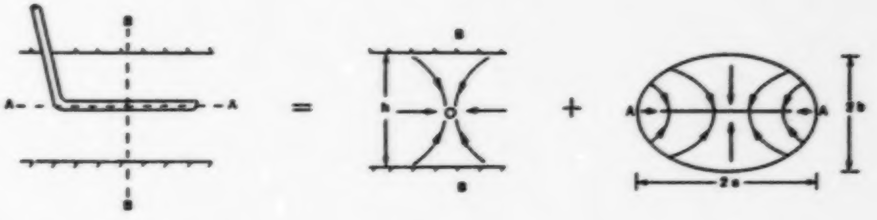


Fig. 1—Vertical and horizontal well drainage volume schematics.



Reference planes AA and BB

Fig. 2—Division of three-dimensional horizontal well problem into two, two-dimensional problems.

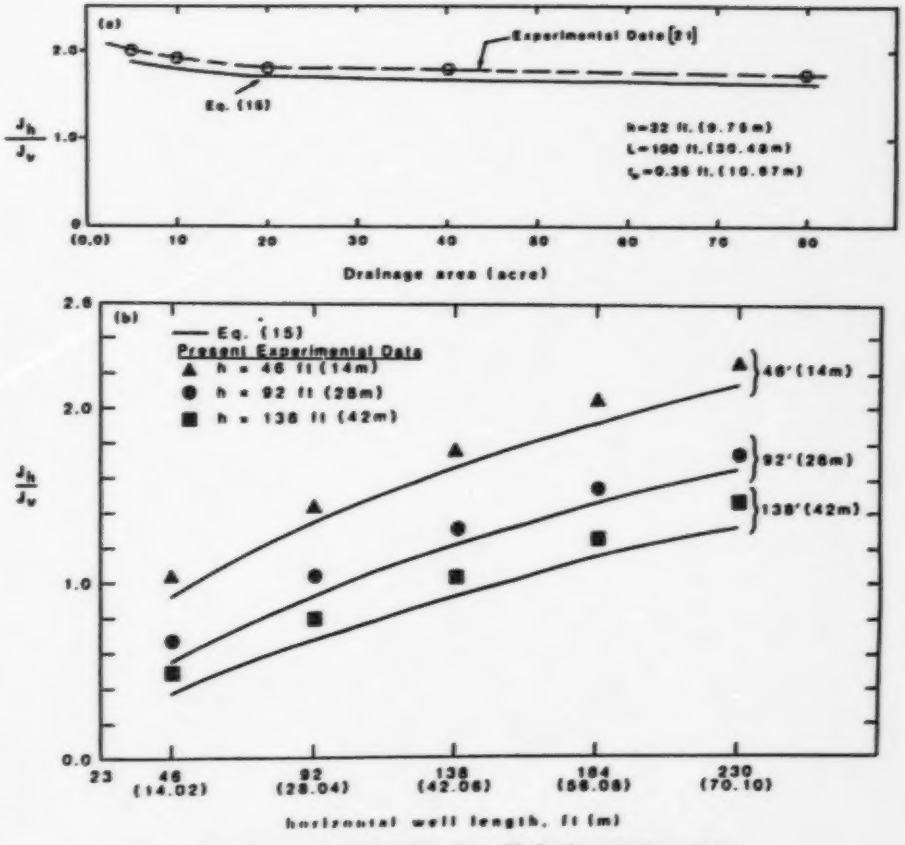


Fig. 3—Comparisons of the laboratory data with the theoretical predictions.

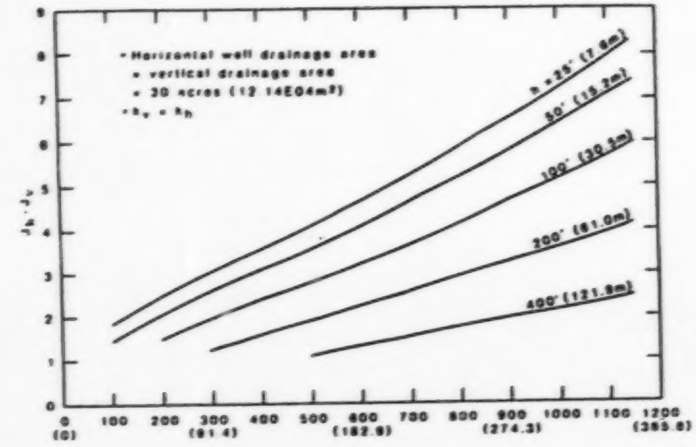


Fig. 4—The influence of reservoir height on horizontal and vertical well productivity indices ratio.

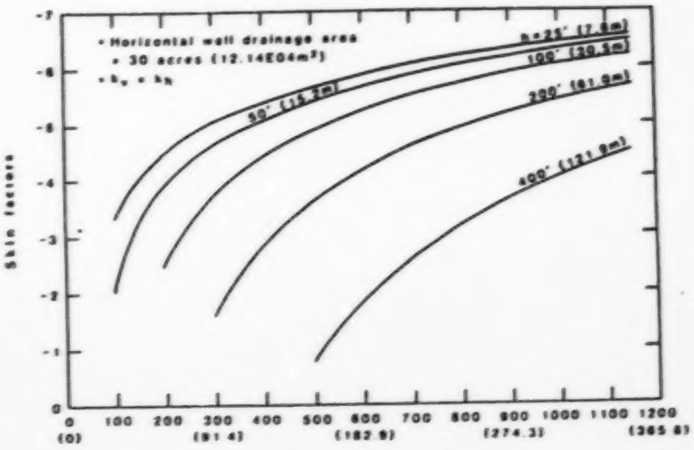


Fig. 5—The influence of reservoir height on horizontal well skin factors.

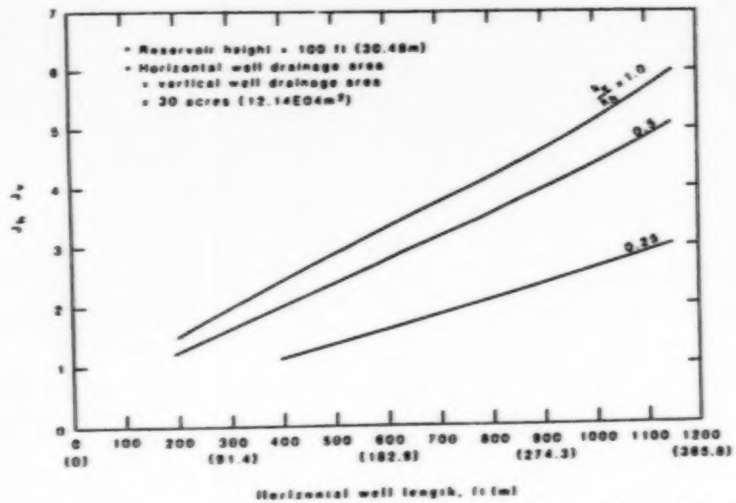


Fig. 6—The influence of reservoir anisotropy on horizontal and vertical well productivity indices ratio.

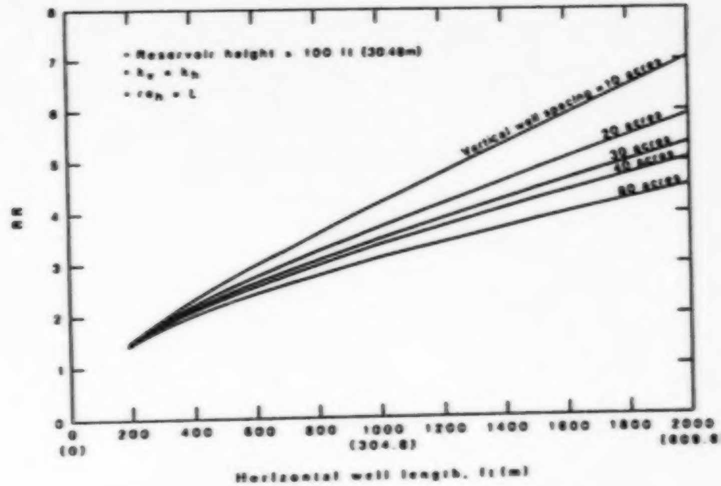


Fig. 7—The influence of well spacing on replacement ratio, RR.

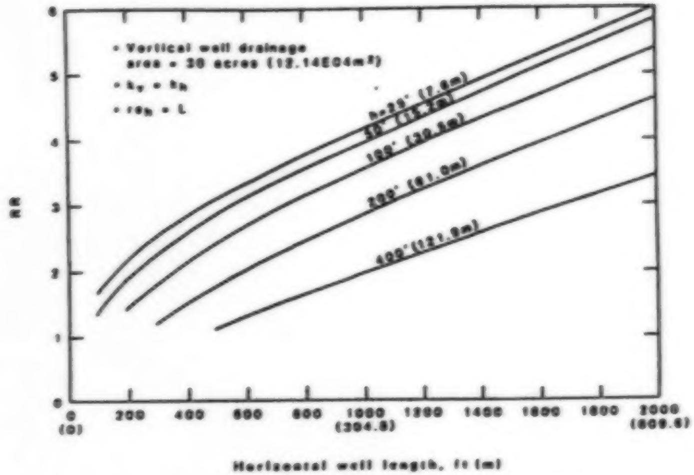


Fig. 8—The influence of reservoir height on replacement ratio, RR.

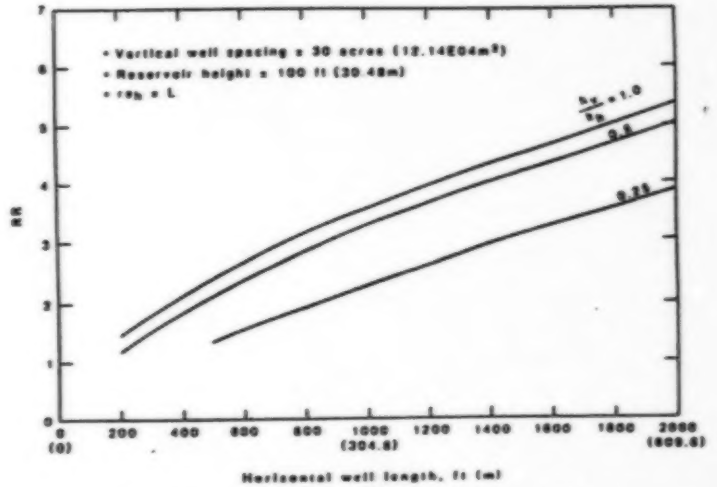


Fig. 9—The influence of reservoir anisotropy on replacement ratio, RR.

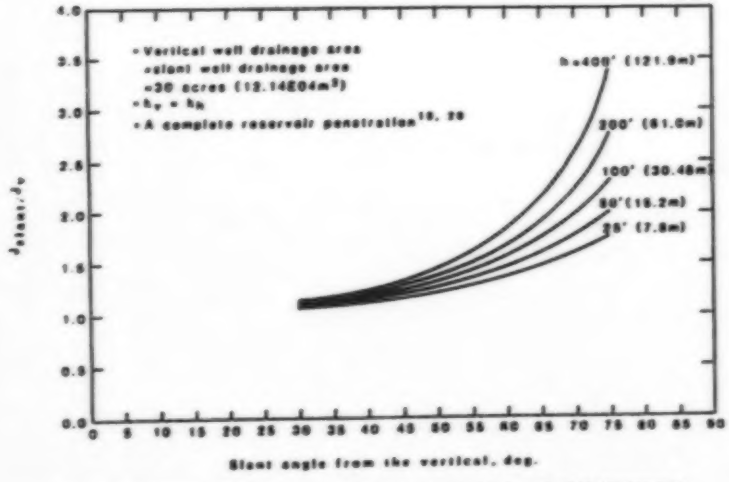


Fig. 10—The influence of reservoir height on slant and vertical well productivity indices ratio.

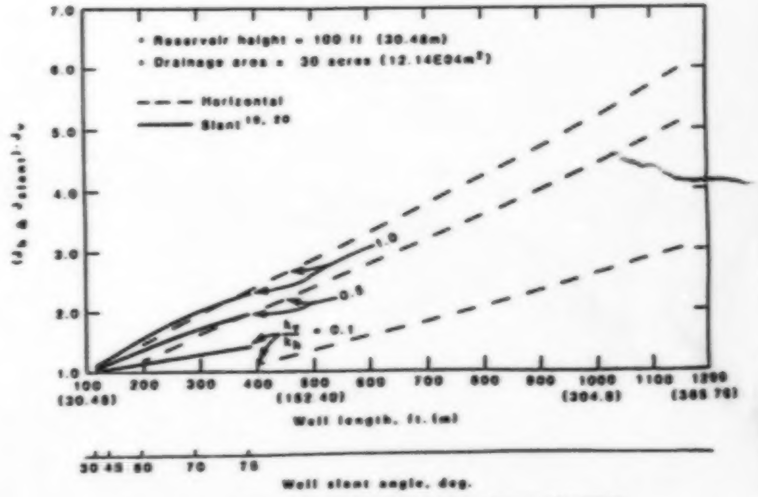


Fig. 11—A comparison of slant and horizontal well performance (h=100 ft).

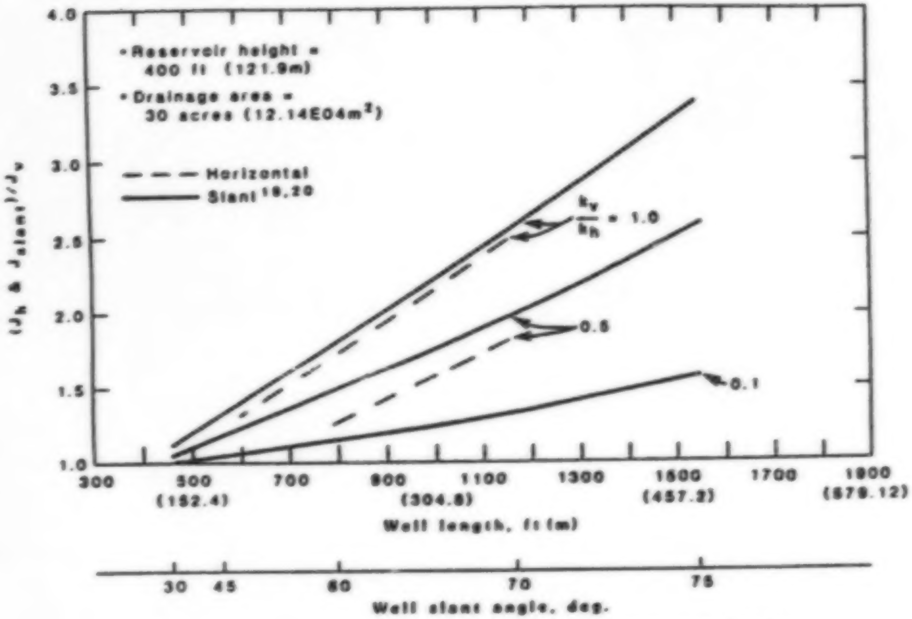


Fig. 12—A comparison of slant and horizontal well performance (h=400 ft).

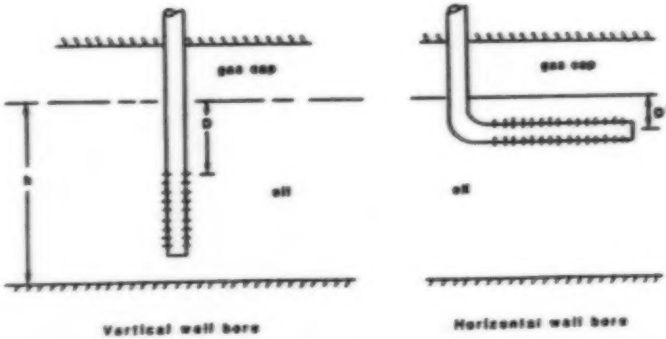


Fig. 13—Gas-coning schematic using vertical and horizontal wells.

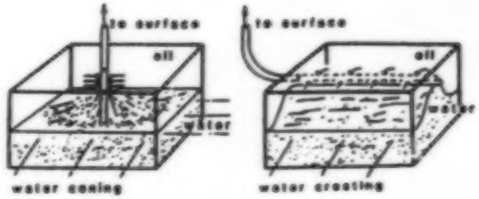


Fig. 14—Water-coning schematic using vertical and horizontal wells.

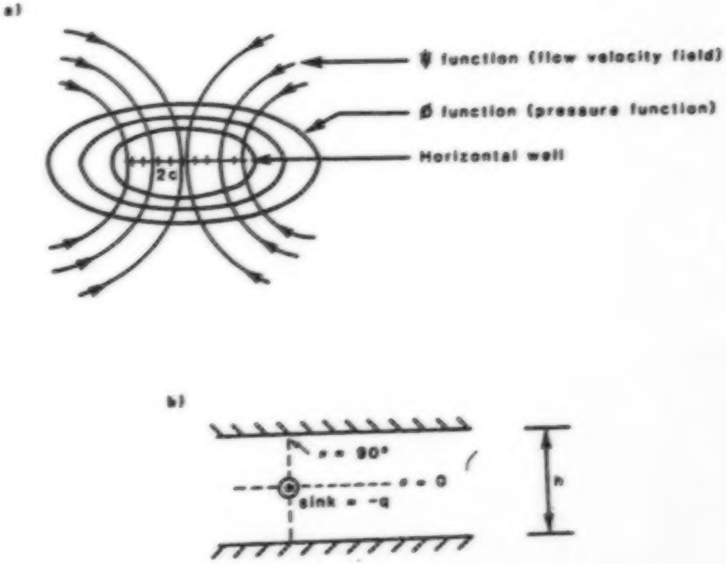

a)
ψ function (flow velocity field)
ø function (pressure function)
Horizontal well
2c
b)
θ = 90°
θ = 0
sink = -q
h

Fig. 15—Schematics of potential flow to a horizontal well: (a) horizontal plane and (b) vertical plane.